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NACE INTERNATIONAL

Standard Practice

Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines

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Foreword

This standard practice formalizes a methodology to assess internal corrosion for onshore and offshore pipelines and other piping systems that normally carry natural gas with condensed water, or with water and liquid hydrocarbons, termed *wet gas internal corrosion direct assessment* (WG-ICDA). This standard is intended for use by gas pipeline operators and others who manage gas pipeline integrity (both onshore and offshore) in which pipelines are normally under wet loading conditions and are beyond the application of NACE SP0206[1] and NACE SP0208.[2]

The WG-ICDA methodology has been developed to meet the needs of gas pipeline operators to assess the integrity of pipelines with respect to internal corrosion. WG-ICDA is a structured process that combines preassessment, indirect inspection, detailed examination, and postassessment to evaluate the effect of predictable pipeline integrity threats such as internal corrosion. Specifically, the goal of WG-ICDA is to identify locations with the greatest likelihood of internal corrosion, and its influencing factors such as water content, flow regime, liquid holdup, flow velocities, temperature changes, and pressure changes. These locations shall be exposed and examined in accordance with criteria established in Section 4. The results of these detailed examinations are used as a basis for assessing the condition and integrity of the remainder of the pipeline segment (with less likelihood of corrosion). WG-ICDA does not depend on the ability of a pipeline to undergo in-line inspection (ILI) by smart pigs or pressure testing, making it most valuable to those pipeline segments unable to accept pigs or that cannot be hydrostatically tested. This standard is intended to be a stand-alone assessment methodology for internal corrosion in lieu of ILI analyses; however, the WG-ICDA methodology may also serve or assist those cases in which ILI may have been performed or is contemplated to demonstrate the reliability of the WG-ICDA process. It may also be used for optimizing the selection/justification or prioritization of pipelines that are subjected to ILI.

In wet gas systems, WG-ICDA subregions of a WG-ICDA region may accumulate water and liquid hydrocarbons. The accumulation of water and liquid hydrocarbons can be determined by a flow model that uses a phase envelope for dew point (water and hydrocarbon) prediction under flowing conditions and shows local temperature, pressure, and gas composition for a pipeline. Depending on the flow conditions (e.g., velocity, gas quality, temperature, pressure, wall surface conditions), the liquid in some WG-ICDA regions and the subsequent WG-ICDA subregions of a pipeline segment can flow or accumulate until the WG-ICDA subregion is full and then carries over to the next downstream WG-ICDA subregion. For specific operating conditions, the liquid can accumulate and remain stagnant within the WG-ICDA subregion (liquid holdup). As liquid continuously travels between accumulation points, the effects of flow regimes shall be considered. These flow dynamic characteristics influence internal corrosion, and thus are a threat to the pipeline integrity.

The goal of WG-ICDA is to identify confirmatory or most probable locations (MPLs) along a WG-ICDA region for determination of the position of assessment sites. These assessment sites are where internal corrosion damage has been identified by means of integrating available historical information in combination with the use of flow models to determine liquid holdup and flow regimes and internal corrosion prediction models (ICPMs) that a pipeline operator deems appropriate for its specific application to predict or calculate internal corrosion rates. The essential focus is the discrimination of conditions along the length of a WG-ICDA region so that possible local WG-ICDA subregion integrity threats with respect to internal corrosion are identified for prioritized damage assessment, repair, and mitigation. WG-ICDA emphasizes damage distribution over absolute corrosion rate, and the ICPMs can fit into the overall process by serving as a tool, whenever possible, to predict wall losses within one flow pattern (e.g., stratified, slug, annular, or annular/mist) within a specific WG-ICDA region and/or WG-ICDA subregion.

This standard was prepared by Task Group (TG) 305, "Internal Corrosion Direct Assessment for Wet Gas Pipelines." TG 305 is administered by Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings." This standard is issued by NACE International under the auspices of STG 35.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*. The terms *shall* and *must* are used to state a requirement, and are considered mandatory. The term *should* is used to state something good and is recommended, but is not considered mandatory. The term *may* is used to state something considered optional.

NACE International Standard Practice

Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines

Contents

Section 1: General

1.1 Introduction

1.1.1 This standard covers the NACE internal corrosion direct assessment (ICDA) process for wet natural gas pipeline systems (i.e., WG-ICDA). It is intended to serve as a guide for applying the WG-ICDA process to onshore and offshore natural gas pipeline systems that:

(a) contain wet gas (gas-liquid ratio [GLR] > 5,000);

(b) are not covered by dry gas internal corrosion direct assessment (DG-ICDA); and

(c) meet the feasibility requirements described in Paragraph 3.3 of this standard.

1.1.2 The two primary purposes of the WG-ICDA methodology are (1) to enhance the assessment of internal corrosion in natural gas pipelines, and (2) to improve pipeline integrity.

1.1.3 The WG-ICDA methodology assesses where along a pipeline segment the internal corrosion severity is potentially highest. The methodology includes existing methods of detailed examination available to a pipeline operator to determine occurrence, as well as the extent and severity, of internal corrosion.

1.1.4 WG-ICDA also uses flow modeling results (e.g., dew point, flow velocities, liquid holdup, and flow patterns) and provides a framework to use those models.

1.1.5 WG-ICDA was developed for onshore and offshore natural gas pipelines that have produced or condensed water as a normal impurity. WG-ICDA is applicable to wet gas gathering and gas producing pipelines.[3,4] The basis of WG-ICDA is for wet gas pipelines and consists of a detailed examination of selected assessment sites with the highest expected corrosion severity where there may be a reduction of the pipe wall thickness to an extent that would pose a threat to the pipeline if mitigation or other measures are not taken before the next assessment. This allows inferences to be made about the remainder of the pipeline segment.

1.1.6 One benefit of the WG-ICDA approach is that, for gas pipelines, an assessment can be performed on a pipeline segment for which alternative methods (e.g., ILI, hydrostatic testing) may be impractical.

1.1.7 WG-ICDA has limitations, and not all pipelines can be successfully assessed with WG-ICDA. These limitations are identified in the preassessment step.

1.1.8 Drips, compressing stations, vessels, and other equipment unrelated to pipelines are not included in this standard.

1.1.9 The provisions of this standard shall be applied by or under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education or related practical experience, are qualified to engage in the practice of corrosion control and risk assessment for pipeline systems. Such persons may be (1) registered professional engineers, (2) recognized as corrosion specialists by organizations such as NACE International, or (3) professionals (i.e., engineers or technologists) with professional experience, including detection/mitigation of internal corrosion and evaluation of internal corrosion on pipelines.

1.1.10 For accurate and correct application of this standard, the standard shall be used in its entirety. Using or referring to only specific paragraphs or sections may lead to misinterpretation or misapplication.

1.1.11 In the process of applying WG-ICDA, other pipeline integrity threats such as external corrosion, mechanical damage, and stress corrosion cracking (SCC) may also be detected. When such threats are detected, additional detailed examination or inspections must be performed to ensure that pipeline integrity is not compromised, regardless of mechanism.

1.1.12 This standard does not address specific remedial actions to be taken when corrosion is found. However, guidance is provided in ASME(1) B31.8[5] and other relevant, jurisdictionally applicable documents. The pipeline operator should use appropriate methods to address threats other than internal corrosion, such as those described in ASME B31.8, ASME B31.8S,[6] API(2) 1160,[7] API 579,[8] CSA(3) Z662,[9] BS(4) 7910,[10] ASME B31G,[11] RSTRENG,[12] NACE standards, international standards, and other documents.

1.2 Four-Step Process

1.2.1 WG-ICDA requires the integration of data from the pipeline's physical characteristics, current and historical operating conditions, multiple field examinations, and inspections to determine the remaining thickness of the pipeline wall.

1.2.2 WG-ICDA includes the following four steps, as shown in Figures 1 through 4. Details of each step are described in Sections 3, 4, 5, and 6.

1.2.2.1 **Step 1—Preassessment**. The *preassessment step* includes the collection and organization of all existing, relevant, essential, historic, and current operating data about the pipeline relevant to assessment of internal corrosion. This includes determining whether WG-ICDA is feasible and defining the pipeline segment to be assessed. This step includes identification of WG-ICDA regions within the pipeline segment based on input, withdrawal, and other parameters described in Paragraph 3.5. The types of data collected are typically available in design and construction records (e.g., topography, routes, material, design pressures, temperatures, and microstructures), operating and maintenance histories, flow rates, alignment sheets, corrosion survey records, gas and liquid analysis reports, and inspection reports from prior integrity evaluations and/or maintenance actions.

1.2.2.2 **Step 2—Indirect Inspection**. The *indirect inspection step* includes the use of techniques for prediction and prioritization of overall corrosion severity at different locations along a pipeline segment to undergo detailed examination (assessment sites). This step also includes definition of the WG-ICDA subregions as a function of flow regimes through multiphase flow modeling, determination of corrosion rates within WG-ICDA subregions, and selection of assessment sites based on corrosion severity converted to wall loss percentages and liquid holdup within these WG-ICDA subregions. Calculations are performed using different proprietary flow models to determine flow regimes and liquid holdup, and ICPMs are used to theoretically estimate corrosion rates. The integration of results from both flow models and ICPMs are analyzed and used to select the MPLs within a WG-ICDA region based on susceptibility to internal corrosion, which are then defined as assessment sites.

1.2.2.2.1 The basis of WG-ICDA indirect inspection is identification of the factors controlled by flow dynamics, factors influencing corrosion severity (see Appendix A [nonmandatory]), factors affecting or controlling corrosion mitigation, upsets, and other corrosion damage-influencing factors, and thus performing a complete assessment process.

1.2.2.2.2 This standard covers internal corrosion related to the transportation of natural gas containing carbon dioxide (CO_2), hydrogen sulfide (H_2S), oxygen (O_2), and/or other corrosive species together with (1) liquid water also containing corrosive species that are typically found in produced or condensed waters associated with natural gas production, storage, and transportation;

(1) ASME International (ASME), Three Park Ave., New York, NY, 10016-5990.
(2) American Petroleum Institute (API), 1220 L St. NW, Washington, DC 2000-4070.
(3) CSA International (CSA), 178 Rexdale Blvd., Toronto, Ontario M9W 1R3, Canada.
(4) British Standard (BS), BSI Group (BSI), 389 Chiswick High Road, London W4 4AL, U.K.

(2) microorganisms that can influence corrosion; (3) solids such as sand deposits, iron sulfide (FeS) as black powder, iron carbonate ($FeCO_3$) or scale; and (4) hydrocarbon liquids.

1.2.2.3 **Step 3—Detailed Examination**. The *detailed examination step* includes performing all actions to allow for detailed examination of assessment sites prioritized to have the highest corrosion severity along with less severe locations identified, as discussed in Section 5. The pipe examination must have sufficient detail to determine the existence, extent, and severity of corrosion. Detailed examination of the internal surface of a pipe may involve nondestructive examination (NDE) methods sufficient to identify and characterize internal defects or wall losses. Detailed examination results are incorporated with the indirect inspection results to help reprioritize assessment sites. Additional data and information gathered using various methods such as long-range ultrasonic testing (LRUT), automated ultrasonic testing (AUT), manual ultrasonic testing (UT), ILI runs, and installation of internal corrosion monitoring devices may be incorporated and used to further prioritize the most damaged locations for detailed examination.

1.2.2.4 **Step 4—Postassessment.** The *postassessment step* is an analysis of data collected from the previous three steps to assess the effectiveness of the WG-ICDA process; prioritize and activate mitigation; establish corrosion control and maintenance strategies; and determine reassessment intervals.

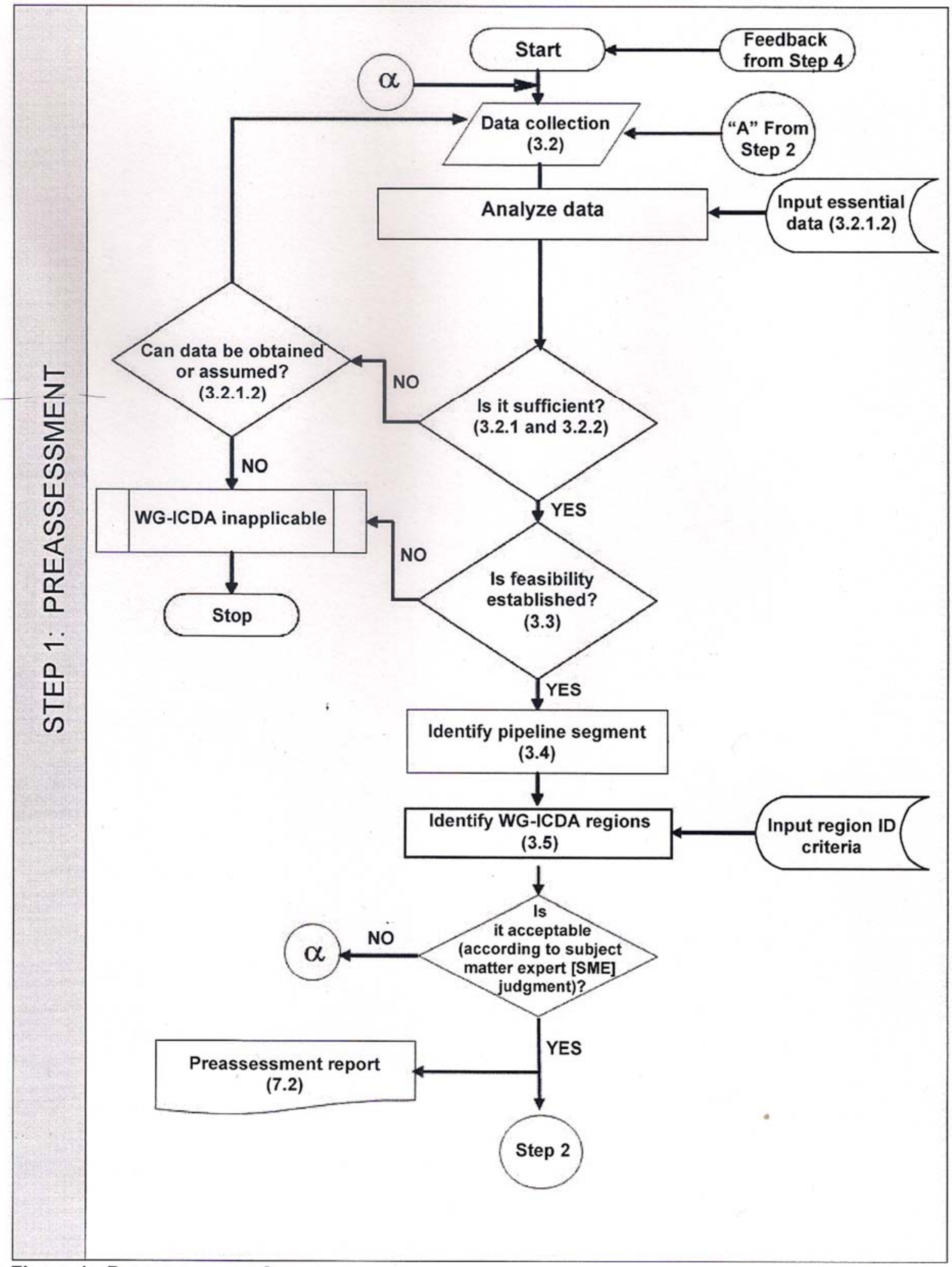

Figure 1: Preassessment Step.
Numbers in parentheses refer to paragraph numbers in this standard.

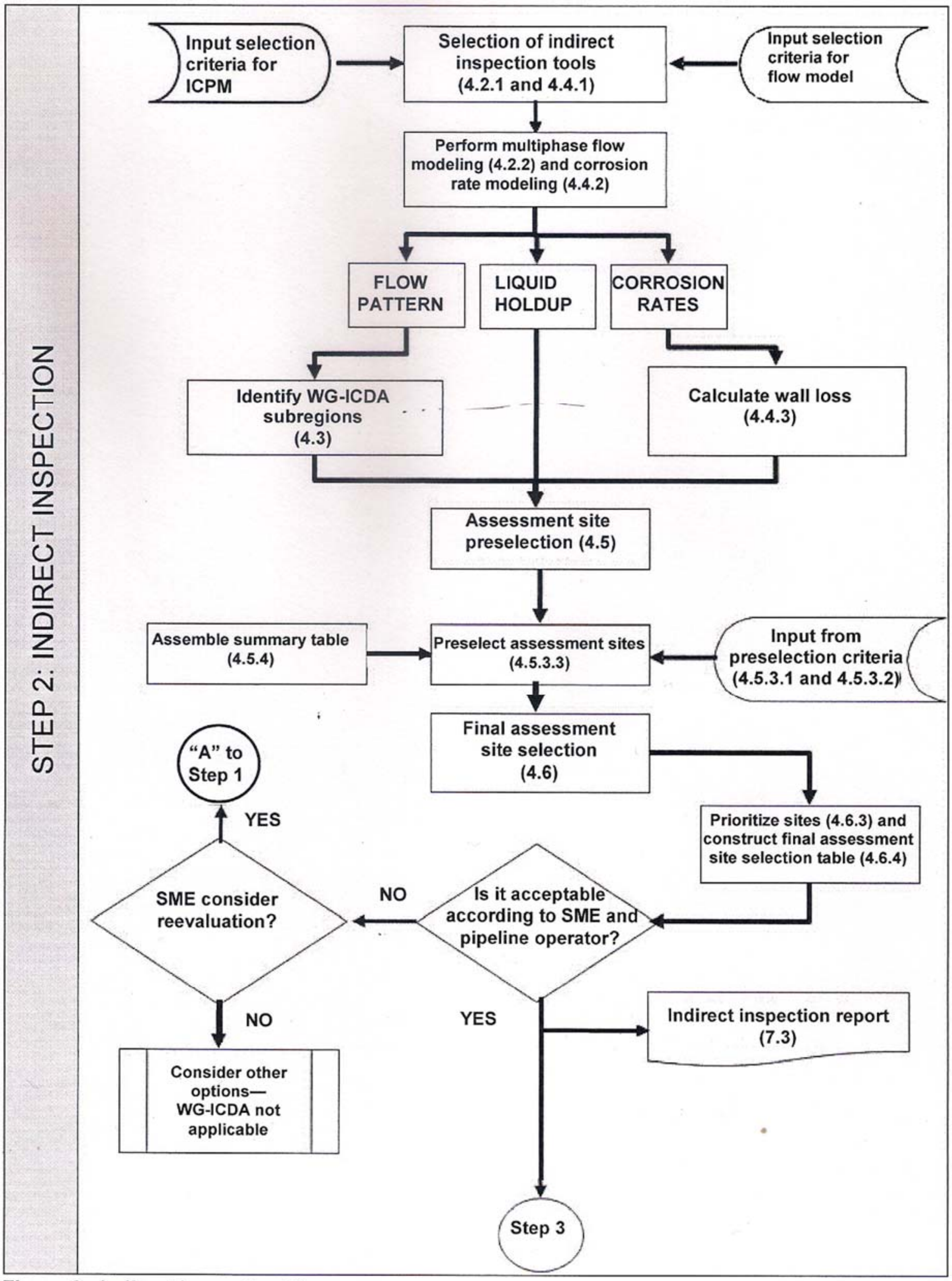

Figure 2: Indirect Inspection Step.
Numbers in parentheses refer to paragraph numbers in this standard.

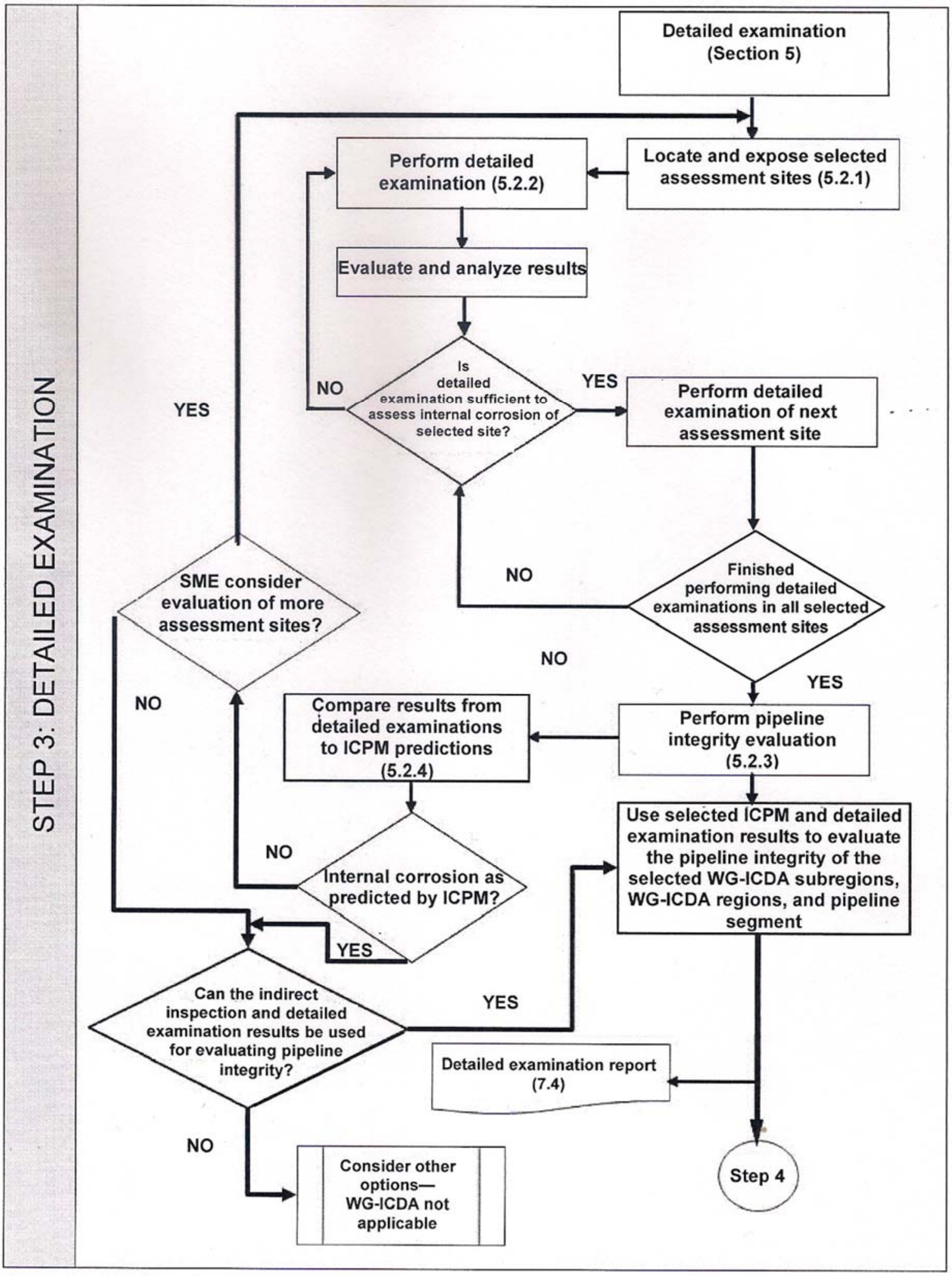

Figure 3: Detailed Examination Step.
Numbers in parentheses refer to paragraph numbers in this standard.

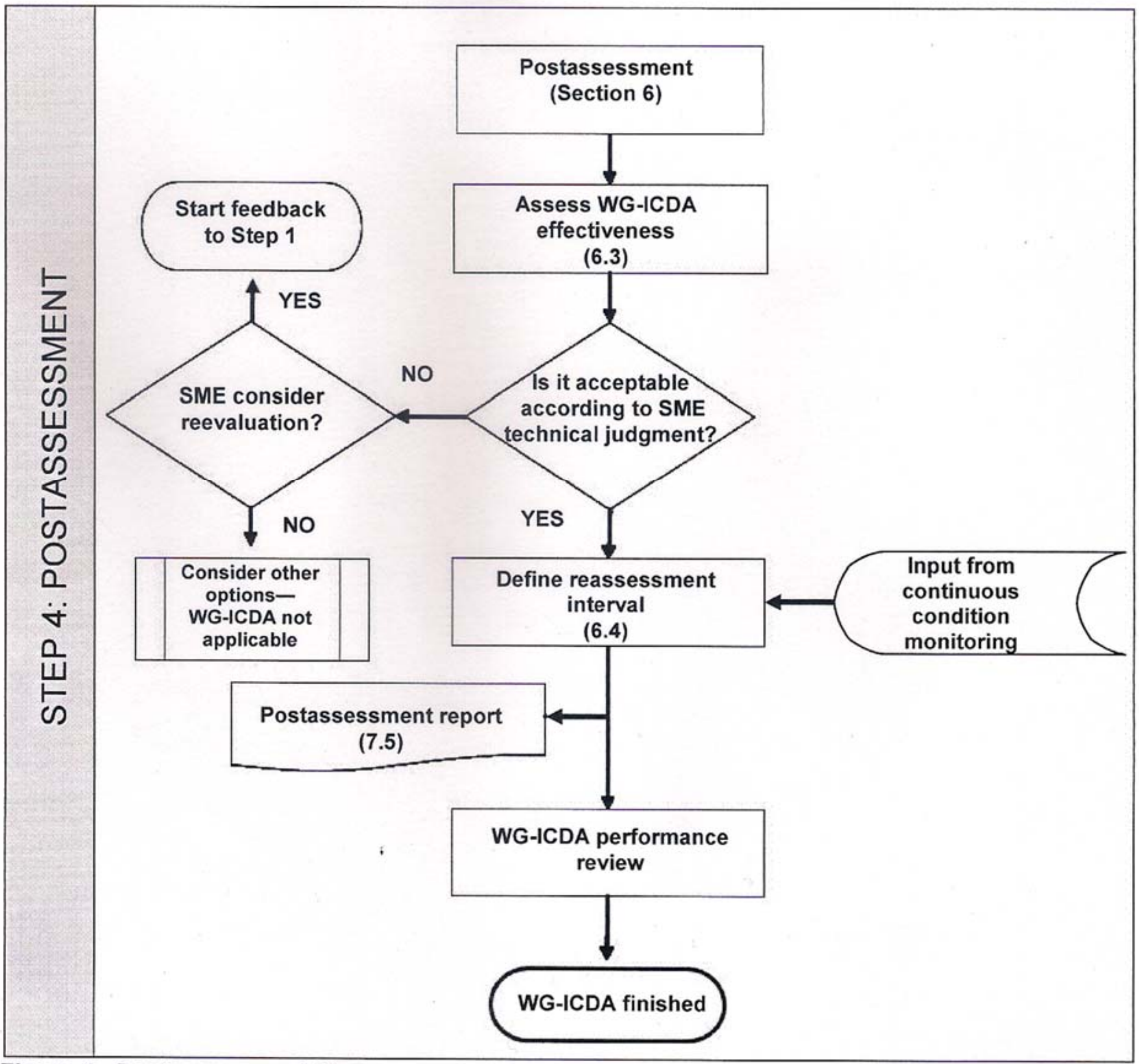

Figure 4: Postassessment Step.
Numbers in parentheses refer to paragraph numbers in this standard.

Section 2: Definitions

Annular Flow: A multiphase flow regime in which fluids are separated into concentric layers, with heavier (i.e., higher-density) fluids flowing in an annular pattern near the pipe wall and lower-density fluids flowing through the center.

Annular/Mist Flow: A multiphase flow regime in which the liquid phase is distributed and carried in the gas phase in the form of liquid droplets, or vice versa. In many instances, an annular area composed of a liquid phase also forms.

Assessment Site: Location within a WG-ICDA subregion that is to be exposed for detailed examination because internal corrosion has been identified and it is the most likely site for corrosion to occur, based on the WG-ICDA analysis.

Automated Ultrasonic Testing (AUT): An automated technique based on ultrasound, used to measure the wall thickness of steel elements, pipelines, vessels, tanks, etc.

Cleaning Pig: A device inserted in a pipeline for the purpose of dislodging and removing accumulated corrodents such as solids or water.

Corrosion: The deterioration of a material, usually a metal, that results from a chemical or electrochemical reaction with its environment.

Corrosion Mechanism: The nature by which corrosion processes occur.

Corrosion Severity: The propensity of an environment to be corrosive, which depends primarily on product quality, liquid chemistry, pressure, temperature, and other influencing factors.

Coupon: A portion of a material or sample, usually flat, but occasionally curved or cylindrical, from which one or more specimens can be taken for testing. For the purposes of this standard, coupons are understood to be strips or pieces of metal that are temporarily placed within a pipeline system for a known period of time. After removal and cleaning, they are examined. The change in mass over the exposure period provides a general corrosion rate. By measuring the depth of individual pits, a pitting corrosion rate can be determined. Specialized analyses can be undertaken to better define corrosion mechanisms.

Detailed Examination: The examination of the pipeline wall at a specific location to determine whether metal loss from internal corrosion has occurred. This is performed using any industry-accepted technology, such as visual inspection, ultrasonic testing, and radiographic testing.

Direct Assessment (DA): A structured process that combines preassessment, indirect inspection, detailed examination, and postassessment to evaluate the effect of predictable pipeline integrity threats such as internal corrosion.

Dry Gas Internal Corrosion Direct Assessment (DG-ICDA): An internal corrosion direct assessment process applicable to normally dry gas systems. (See NACE SP0206.)

Electrical Resistance (ER) Probe: A method for monitoring corrosion based on the change of electrical resistance over time of the exposed element to a sweet corrosive environment.

Fluid: A substance that continually deforms (flows) under an applied shear stress. Both liquids and gases are fluids.

Flow Pattern (Flow Regime): The distribution of the gas phase and the liquid phase as they flow through the pipeline. It is dependent on both superficial gas and liquid velocities.

Gas-Liquid Ratio (GLR): The ratio of the volumetric flow rate of the gas to the volumetric flow rate of the liquid (water + hydrocarbon) at standard conditions. The volumetric flow rates of the gas and liquid are expressed in the same unit of measure (e.g., standard cubic meters per unit time or standard cubic feet per unit time).

Gathering System: Pipeline and related facilities to collect and move produced gas progressively starting from individual wells to a trunk, common, or main line. Produced gas compositions often may not meet gas quality specifications typical of gas transmission systems.

High-Priority Assessment Site: An assessment site that is qualified as high priority by a subject matter expert (SME) based on its location within a high-consequence area, failure/leak history, or other technically justified criteria.

Hydrostatic Testing: The testing of sections of a pipeline performed by filling the pipeline with water and pressurizing it until the nominal hoop stresses in the pipeline reach a specified value.

Internal Corrosion Predictive Model (ICPM): Engineering and mathematical correlations used to predict the internal corrosion rate. It may include variables such as flow, superficial liquid velocity and superficial gas velocity, topography, content of CO_2 and H_2S, pressures, temperatures, liquid holdup, and pH. Appendix B (nonmandatory) lists a number of ICPMs used to predict internal corrosion rates in oil and gas pipelines.

Indication: Any measured deviation from the normal pipeline wall thickness (corrected for mill tolerance).

Indirect Inspection: The use of tools, methods, or procedures to evaluate a pipeline indirectly. It consists of performing flow and corrosion rate modeling techniques and using the results to select locations along a pipeline where there is likelihood of corrosion and the use of the WG-ICDA process to identify assessment sites.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipe using an ILI tool. The tools used to conduct ILI are known as pigs, smart pigs, or intelligent pigs.

Internal Corrosion Direct Assessment (ICDA): A direct assessment process for internal corrosion, applicable to both dry gas and wet gas. In some jurisdictions, this qualifies in part as an engineering assessment.

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Liquid Holdup: Accumulation of liquid remaining within a pipeline segment (i.e., input liquid volume is greater than output liquid volume) under multiphase flow conditions, with units of absolute liters (absolute barrels). It is estimated with multiphase flow modeling correlations and is dependent on variables such as superficial gas and liquid velocities, liquid and gas densities, pipeline diameter, and pipeline inclination angle.

Mitigation: Activities taken to reduce the internal corrosion severity inside a pipeline. For the purposes of this standard, the objectives are to (1) determine the effectiveness of mitigation measures on the internal corrosion threat to establish priority in selecting candidates for the WG-ICDA process, (2) correlate the mitigation technique data from a detailed examination (e.g., inspection, cut out) to the history of operations and mitigation, and (3) determine, in the postassessment step, the most effective mitigation measures to be taken after a detailed examination.

Mixture Velocity: The sum of the superficial gas and superficial liquid velocities.

Natural Gas: Primarily methane as produced from natural sources. Natural gas does not normally contain H_2S, but it may, for evaluation purposes in this standard, include H_2S, CO_2, and O_2.

Pigging: See *In-Line Inspection* or *Cleaning Pig.*

Radiographic Testing (RT): A NDE method to evaluate the condition of pipeline walls.

Region: See *WG-ICDA Region.*

Segment: A portion of a pipeline that is assessed using WG-ICDA. A segment may consist of one or more WG-ICDA regions.

Slug Flow: A multiphase fluid flow regime characterized by a series of liquid plugs (slugs) separated by relatively large gas pockets.

Subject Matter Expert (SME): A professional (usually, but not limited to a professional engineer) with documented and sufficient experience or engineering knowledge to perform an activity within a specific subject in a professional manner and whose actions and work conduct are expected to be acceptable to external scrutiny. A SME should have NACE International certification.

Stratified Flow: A multiphase flow regime in which fluids are separated into distinct strata or layers, with lighter fluids flowing above heavier (i.e., higher-density) fluids.

Superficial Gas Velocity: The volumetric flow rate of gas at system temperature and pressure divided by the cross-sectional flow area of the pipe.

Superficial Liquid Velocity: The volumetric flow rate of liquid (water or water plus hydrocarbons) at system temperature and pressure divided by the cross-sectional flow area of the pipe.

Upset: A situation in which the pipeline operation differs from normal or steady state; it occurs over a relatively short time duration. This change may be caused by design or accidents. Upsets can result in a change of flow, change of fluid chemistry, or change of pipeline internal surface condition. These can all potentially influence internal corrosion in the pipeline. Upsets occur mainly during start-up (commissioning), temporary shutdowns, restart, or a plant turnaround. In contrast to normal operations, upsets result in a more dramatic change of the pipeline operation.

Ultrasonic Testing (UT): Techniques based on ultrasound used to measure the wall thickness of steel elements, pipelines, vessels, tanks, etc.

Wet Gas: In the broad context, wet gas is defined as gas containing condensable hydrocarbons or water below their dew points (i.e., free liquids exist). For the purposes of this standard, wet gas may be defined as any gas that does not meet the dry gas requirements.

Wet Gas Internal Corrosion Direct Assessment (WG-ICDA): An ICDA process as defined in this standard that is applicable to wet gas systems.

WG-ICDA Region: A continuous length of pipeline determined by input, withdrawal, processing, and other characteristics within a pipeline segment. The cumulative number of WG-ICDA subregions in a pipeline segment with a common input and discharge locations constitute a WG-ICDA region.

WG-ICDA Subregion: A continuous length of pipeline (including weld joints) that is limited by changes with respect to flow patterns and/or elevation profile.

Section 3: Step 1—Preassessment

3.1 Introduction

3.1.1 The objectives of the *preassessment step* are:

3.1.1.1 To collect information related to the pipeline, terrain, and fluids handled;

3.1.1.2 To determine whether WG-ICDA is feasible for the pipeline being evaluated; and

3.1.1.3 To identify WG-ICDA regions.

3.1.2 The *preassessment step* (see Figure 1) must be performed in a comprehensive and thorough manner.

3.2 Data Collection

3.2.1 The pipeline operator shall collect historical (i.e., throughout the life of the pipeline) and current data, along with physical information for each pipeline segment evaluated.

3.2.1.1 The pipeline operator shall define minimum data requirements based on the history and condition of the pipeline segment. In addition, the pipeline operator shall identify data elements that are critical to the success of the WG-ICDA process.

3.2.1.2 Table 1 provides a list of data that are typically collected. In Table 1, the data designated as "Importance Level 1" are the *minimum* required data to perform a WG-ICDA. Data designated as "Importance Level 2" are additional data that are desirable to have for completeness of the WG-ICDA process, but their absence does not compromise the WG-ICDA process. The SME shall define whether a missing piece of Importance Level 2 data can be obtained or inferred using other methods, and this must be well documented.

3.2.1.3 All parameters that affect the identification of WG-ICDA regions (see Paragraph 3.5) shall be considered for initial WG-ICDA process applications on a pipeline segment.

3.2.1.4 Accurate and complete elevation profile and flow rate data must be used for predicting the locations of water and solids accumulation.

3.2.1.5 Accurate information regarding pipeline operating and maintenance activities related to internal corrosion must be used to determine the probability of significant internal corrosion damage.

3.2.2 The pipeline operator shall collect, at a minimum, all Importance Level 1 data from the following categories, as shown in Table 1. In addition, the pipeline operator may determine that items not included in Table 1 are necessary.

3.2.2.1 Operating history;

3.2.2.2 System design information (e.g., pipe grade, wall thickness of pipe, and maximum operating pressure [MOP]);

3.2.2.3 Presence of liquid water (including upsets);

3.2.2.4 Water and solids content in fluids;

3.2.2.5 Composition of gas and liquids;

3.2.2.6 Presence of H_2S, CO_2, and O_2;

3.2.2.7 Maximum and minimum flow rates;

3.2.2.8 Pipeline elevation profiles;

3.2.2.9 Internal corrosion leak or failure history;

3.2.2.10 Internal corrosion identified using LRUT, ILI, UT, AUT, or visual inspection;

3.2.2.11 Mitigation currently being applied to control internal corrosion or what has been historically applied;

3.2.2.12 Other known and documented causes of internal corrosion, such as microbiologically influenced corrosion (MIC); and

3.2.2.13 Dates of all recorded events.

Table 1
Typical Data for Use of WG-ICDA Methodology

CATEGORY	DATA TO COLLECT	IMPORTANCE LEVEL
Defined length	Include the length between inputs/outputs and processing, segment, WG-ICDA region and WG-ICDA subregion length.	1
Diameter and wall thickness	Include the nominal pipe diameter and wall thickness.	1
Pipeline characterization	Include materials specification in accordance with API 5L[13] grade, CSA Z245.1[14] grade, or other international grades; microstructure; weld type and material; chemical composition; and geometries (elbows, tees, expansions, reductions, etc.). Also include the pipeline material, microstructure, and weld material.	1
Accessories	Description and location of accessories such as sampling points, temperature and pressure gauges, and valves. Safety valve set points and maintenance program.	1
Operating history	Include periods of inactivity or abnormal activity, change in gas flow direction, type of service, removed taps, year of installation, etc. Determine whether the pipeline has ever been used previously for crude oil or other liquid products. In addition, gather data concerning the length of time that pipelines in storage fields are being used for injection (normally dry), withdrawal (normally wet), or have been inactive. Other contributors to internal corrosion data include the location of sludge deposits, hydrates, emulsion, etc. Determine the date of construction, and also collect all process information, especially upstream of the pipeline segment, as these aid in understanding upsets and the effect on the pipeline segment. Pressure and temperature profile history. Records for understanding the processes located upstream of the pipeline segment—reliability, history, upsets, etc.	1
Flow rate	Include flow rates—normal, maximum, and minimum flow rates at minimum and maximum operating pressures for all inlets and outlets. Significant periods of low or no flow.	1

CATEGORY	DATA TO COLLECT	IMPORTANCE LEVEL
Elevation profile	Collect topographical data (e.g., USGS[(5)] data), including consideration of pipeline depth of cover.	1
Gas quality (analyses)	Collect gas and liquid analyses, and any bacteria testing results for the pipeline and on shipper and delivery laterals. Also collect gas chromatographic analysis (at least performed up to C12+), including methane (CH_4), H_2S, CO_2, specific gravity, and gas density. Include the relationship of gas analyses to pipe location. The presence of any solids or dusts being carried in the pipeline may have an effect on the corrosion severity. Any level of O_2 shall also be included.	1
Pressure	Include normal, minimum, and maximum operating pressures. Design pressure should also be collected.	1
Temperature	Include temperature profile along pipeline length. Useful parameters include compressor discharge temperature, soil temperature, and any temperature along the pipeline where measured.	1
Inputs/outputs	Identify all locations of current and historic inputs and outputs to the pipeline.	1
Repair/maintenance data	Include the presence of solids, indications, pipe section repair and replacement, prior inspections, and NDE data, as well as any cleaning pig locations, frequencies, and dates. Other information includes analytical data of all removed sludge and liquids from liquid separators or when cleaning pigs were used, hydrators, etc. Include analysis performed to determine chemical properties and corrosion severity of the removed products, including the presence of bacteria.	2
Corrosion inspection and corrosion monitoring information	This information may include data from previous ILI runs, NDE methods used (e.g., UT and RT), as well as corrosion rate data from coupons, ER probes, linear polarization resistance probes, electrochemical noise sensors, and any other corrosion monitoring devices used by the pipeline operator. In addition, any time that a pipeline is cut open, information on internal condition of the pipe should be evaluated. Dates and relationship of monitoring to pipe location, corrosion rate recorded/calculated, and accuracy of data (see NACE Publication 3T199).[15]	2

[(5)] U.S. Geological Survey (USGS), 12201 Sunrise Valley Dr., Reston, VA 20192.

CATEGORY	DATA TO COLLECT	IMPORTANCE LEVEL
Other data that influence internal corrosion	These data are defined by the pipeline operator, such as locations of solids, scale, sludge, and hydrates.	2
Leaks/failures	Include the locations and nature of leaks/failures.	2
Cleaning pig history	Include the frequency and effectiveness of cleaning pigs.	2
Hydrostatic testing information	Include past presence of water and hydrostatic test water quality data.	2
Water analyses and volumes	Physical-chemical characterization of the water and characterization of other liquids found. Determine the volume of water transported by the pipeline. Include the source of water (condensed water vs. free water from the underground reservoir), and drips and separators, which are locations where free water is collected. Also include water dew point.	2
Liquid chemistry	The chemistry of the liquid phase has a direct bearing on the corrosion severity of the pipeline. This includes the presence of scale in free water, as well as the presence and quantity of hydrocarbons.	2
Corrosion inhibitor	Include information about injection, chemical type, and dose. This information shall also include when inhibition was started, how long it was used, and how effective it was. Also include batch or continuous, solubility, and dispersibility in hydrocarbon and aqueous phases. Collect information on biocide treatments.	2
Type of dehydration	Determine whether dehydration was performed using glycols.	2
Internal coatings	Include the existence and location(s) of internal coatings.	2
Hydrate prevention treatments	Include injection volumes for liquids being injected into the system to prevent the formation of hydrates. Methanol is often used.	2
Upsets	Include the frequency, nature of upset (intermittent or chronic), volume (if known), and nature of liquid.	2

3.3 WG-ICDA Feasibility Assessment

The pipeline operator shall examine the data collected as defined in Paragraph 3.2 to determine whether conditions that would preclude this WG-ICDA application or for which indirect inspection tools cannot be used.

The following conditions are required to apply this WG-ICDA standard:

3.3.1 All Importance Level 1 information shall be obtained.

3.3.2 The pipeline is expected to be wet, with either a continuous or periodic water phase being present at some point along a WG-ICDA region or throughout a whole WG-ICDA region during normal operations.

3.3.3 The pipeline must be accessible to perform the detailed examination. Right of ways (ROWs) may not be the property of the pipeline operator and thus access can be denied.

3.3.4 The pipeline operator understands that all four steps of the WG-ICDA process shall be performed.

3.3.5 A reliable (or conservative) reassessment interval cannot be determined.

3.3.6 If there are any Importance Level 2 data missing, the SME shall make corresponding technically supported and documented assumptions to validate his or her assessment.

3.4 Identification of Pipeline Segment

The pipeline operator shall define a pipeline segment from the data collected in the preassessment step. A segment is a portion of a pipeline of any length that consists of one or more WG-ICDA regions. It is the total length of pipeline on which the WG-ICDA process is performed.

3.5 Identification of WG-ICDA Regions

The pipeline operator shall define WG-ICDA regions from the data collected in the preassessment step.

3.5.1 A WG-ICDA region is a portion of pipeline with a defined length. A defined length is any length of pipeline between each point of input or withdrawal of process fluids. In the case of a WG-ICDA region with bidirectional flow schemes (e.g., gas storage input and withdrawal operations), a separate WG-ICDA region shall be established for each flow direction. The following characteristics may also be considered in the identification of WG-ICDA regions:

3.5.1.1 Unit operation changes, such as temperature and pressure that arise from the use of line heaters or compression facilities, respectively;

3.5.1.2 Location of chemical injection points; and

3.5.1.3 Location of valves, appurtenances, and/or pig traps located within the segment.

3.5.2 Once the individual WG-ICDA regions have been identified, the user shall superimpose all individually identified WG-ICDA regions into as many resulting WG-ICDA regions for the pipeline segment. Appendix C (nonmandatory) includes an example of how to perform this step.

Section 4: Step 2—Indirect Inspection

4.1 Introduction

4.1.1 The objective of the *indirect inspection step* is to identify WG-ICDA subregions within each WG-ICDA region where the pipeline segment is most likely to experience or has experienced internal corrosion damage and to identify these as a function of distance and elevation. Modeling may be used to identify these locations within the WG-ICDA subregion. Once the identification analysis has been performed, these locations within the WG-ICDA subregion that are most likely being exposed to internal corrosion damage may then be ascribed assessment site status as appropriate (based on calculated wall losses incurred) and may be candidates for detailed examination.

4.1.2 The *indirect inspection step* requires the understanding of the influence of a variety of operating parameters including, but not limited to, superficial gas and liquid velocities, flow patterns, pipeline elevation profile, liquid holdup, and possible locations for solids accumulation, on the prediction of corrosion severity. Locations within the WG-ICDA subregions that are predicted to have both a range of corrosion rates (low through severe) as well as the highest internal corrosion rates may become high-priority assessment sites, which are selected for detailed examination in accordance with minimum number of assessment sites criteria based on the total length of the pipeline segment. This process may also follow the investigative process of a SME through the use of risk-based methodologies (not covered in this standard). The historical operation of the pipeline must be considered, and corrosion rate modeling must be performed for several different scenarios, as operating conditions may have changed over time. The *indirect inspection step* uses this analysis to identify potential assessment sites for detailed examination.

4.1.3 The indirect inspection step (see Figure 2) shall include each of the following activities for each WG-ICDA region:

4.1.3.1 Performing multiphase flow modeling using collected data to determine the flow pattern, pressure and temperature profiles, liquid holdup, and sand/solid settling velocities for prediction of sand/solid accumulation, and integrating the flow calculation results with the pipeline elevation profile;

4.1.3.2 Identifying other factors for the pipeline segment that influence internal corrosion or corrosion location such as non-steady-state flow, or from historical pigging operations;

4.1.3.3 Identifying WG-ICDA subregions based on the flow patterns developed within each WG-ICDA region;

4.1.3.4 Predicting the corrosion severity within each WG-ICDA subregion using corrosion rate models or sound and technically supported engineering judgment, or both; and

4.1.3.5 Selecting the assessment sites as a function of corrosion severity.

4.2 Multiphase Flow Modeling

4.2.1 Any appropriate method to predict fluid behavior along the pipeline length is acceptable, but is not the definitive criteria for predicting internal corrosion. There are many commercially available models to perform multiphase flow modeling. Multiphase flow modeling provides insights into the flow-determined variables along the pipeline segment that are used for prediction of internal corrosion rates as well as defining the WG-ICDA subregions. Among the principal variables that are used from multiphase flow modeling simulations are:

4.2.1.1 Changes in superficial gas velocity;

4.2.1.2 Changes in superficial liquid velocity;

4.2.1.3 Changes in pressure and temperature;

4.2.1.4 Changes in gas behavior that leads to liquid (condensate, water) condensation;

4.2.1.5 Changes in liquid holdup; and

4.2.1.6 Changes in flow regimes.

4.2.2 The values of the variables listed in Paragraphs 4.2.1.1 through 4.2.1.6 that result from the multiphase flow models or ICPMs must be validated against real operational conditions or current operating history. This provides assurance that the models actually represent the process conditions within the pipeline segment. If the flow model does not reproduce the real field conditions, then the model or modeling approach shall be adjusted accordingly (i.e., by selecting another fluid flow correlation) until the operational conditions in the pipeline segment are reproduced. It is the responsibility of the SME to follow the corresponding process to achieve reproducibility.

4.2.2.1 Many of the ICPMs listed in Appendix B already have embedded correlations to model multiphase flows, as well as liquid holdup. This is an integral way of performing the indirect inspection step, as these ICPMs use the results from the multiphase flow simulations internally as input for the internal corrosion rate prediction.

4.2.2.2 In other cases, flow modeling may be performed separately using commercially available software, and the results subsequently used as input to the corrosion rate modeling.

4.2.2.3 Both methods are acceptable. It is the responsibility of the SME and the pipeline operator to select which method to use.

4.3 Identification of WG-ICDA Subregions

4.3.1 A WG-ICDA subregion is a continuous length of pipeline contained within a WG-ICDA region that is defined and limited by changes with respect to flow patterns, which can be influenced significantly by:

- Changes in elevation profile with respect to the vertical plane;
- Changes in pipeline direction with respect to the horizontal plane; and
- Changes in pipeline internal diameter.

4.3.2 The changes listed in Paragraph 4.3.1 promote pressure and temperature changes that result in changes in superficial gas and liquid velocities, thereby causing the development of new or different flow patterns. These allow the WG-ICDA subregion location to be narrowed as a function of flow pattern. Appendix C provides examples of how WG-ICDA subregions are identified.

4.4 Corrosion Rate Modeling and Wall Loss Determination

4.4.1 The results from flow modeling and ICPMs are used to predict internal corrosion rates at various points or intervals within each WG-ICDA subregion. This may be done by integrating the results of separate multiphase flow models with ICPMs that do not have the flow modeling subroutine built into the algorithm, or by using ICPMs that have the flow modeling capabilities built into the algorithm. Appendix B lists a number of published ICPMs used to determine internal corrosion rates in oil and gas pipelines. NOTE: None of these ICPMs are endorsed by NACE—selection or use of these or other ICPMs is predicated by pipeline operator experience or choice/recommendation by a SME.

4.4.2 Internal corrosion rates within each WG-ICDA subregion shall be determined at discrete points or intervals to facilitate the location of assessment sites within the WG-ICDA subregion.

4.4.2.1 The maximum interval length at which corrosion rates shall be determined is 50 m (160 ft). Within a WG-ICDA subregion, there may be many intervals depending on the length of the WG-ICDA subregion. For example, a 100 m (330 ft) long WG-ICDA subregion with a corrosion rate determination interval of 25 m (82 ft) contains four locations at which the internal corrosion rates are calculated.

4.4.2.2 Where corrosion inhibition has been or is being used, the pipeline operator must apply a correction factor to the ICPM (if it is not already embedded in the model) to account for the dampening or reduction in corrosion rates over the entire service life of the pipeline segment being evaluated. This process of corrosion rate reduction shall be thoroughly documented by the SME to support the corrected wall loss prediction.

4.4.3 The computed internal corrosion rates for each WG-ICDA subregion shall be converted to wall losses (over the discrete time interval under review) and shall also address possible changes in corrosiveness that may have occurred during discrete time intervals as a result of significant events such as start-up, reduction in effluent flow (typical in production operations), increased pipeline gas and water volumes, introduction of O_2, or introduction of corrosion inhibitors. These influencing factors allow the cumulative computation of anticipated general wall loss and localized pitting at different time intervals over the operating history of the pipeline segment, and if the pitting factor is known, the anticipated wall loss may be determined using historical or laboratory data.

4.5 Assessment Site Preselection

4.5.1 The pipeline operator must determine the assessment sites within a WG-ICDA subregion based on a set of engineering-based criteria from the SME analysis of the data provided in the preassessment step and the results from the multiphase flow modeling and corrosion rate and wall loss determinations.

4.5.2 The assessment sites shall be prioritized in accordance with the cumulative wall loss (corrected for both wall thickness tolerance and internal corrosion inhibition effectiveness, if applicable) based on ICPM uninhibited corrosion rates.

4.5.3 For every WG-ICDA region and WG-ICDA subregion that has been identified in the pipeline segment, the pipeline operator shall use the following criteria to preselect assessment sites. NOTE: Each criterion is independent from the other.

4.5.3.1 Preselection Criterion 1—Wall Loss

4.5.3.1.1 Select the WG-ICDA region to be analyzed. Within the selected WG-ICDA region, take the average of all the calculated wall loss percentage values for every WG-ICDA subregion.

4.5.3.1.2 Select the WG-ICDA subregion locations with wall loss percentage values above the average. If the SME chooses to preselect locations based on criteria other than the wall loss percentage above the average, then the criteria must be documented.

4.5.3.2 Preselection Criterion 2—Liquid Holdup

4.5.3.2.1 Within the selected WG-ICDA region, take the average of the liquid holdup values for every WG-ICDA subregion.

4.5.3.2.2 Select, within each WG-ICDA subregion, the locations with liquid holdup values above the average liquid holdup.

4.5.3.3 Combine both preselection criteria (Paragraphs 4.5.3.1 and 4.5.3.2) to preselect the assessment site for each WG-ICDA subregion.

4.5.4 A summary table shall be assembled that describes the coordinates and physical boundaries of all WG-ICDA regions and WG-ICDA subregions and provides the proper information at all locations therein on pressure, temperature, liquid holdup, superficial liquid and gas velocities, flow pattern, corrosion rate and wall loss, liquid holdup and wall loss averages, preselection criteria, etc. The pipeline operator shall use this summary table to indicate the preselection of assessment sites.

4.5.4.1 Table 2 shows the summary table that shall be produced.

4.5.4.2 Table C1 in Appendix C provides a completed example of the summary table.

Table 2
Summary Table

WG-ICDA Region #	Paragraph # for Criteria	Length of WG-ICDA Region	Coordinates	Description	WG-ICDA Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup	Superficial Liquid Velocity	Superficial Gas Velocity	Mixture Velocity	Flow Pattern	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		m (ft)				m (ft)	m (ft)	kPa (psig)	°C (°F)	L abs. (bbl abs.)	m/s (ft/s)	m/s (ft/s)	m/s (ft/s)		mm/y (mpy)	%	
N			X1, Y1, Z1 to X2, Y2, Z2	Physical description of the WG-ICDA region boundaries	1												
									Average						Average		
					2												
									Average						Average		
					3												
									Average						Average		
N + 1					1												
									Average						Average		
					2												
									Average						Average		

Table 2
Summary Table
(continued)

WG-ICDA Region #	Paragraph # for Criteria	Length of WG-ICDA Region	Coordinates	Description	WG-ICDA Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup	Superficial Liquid Velocity	Superficial Gas Velocity	Mixture Velocity	Flow Pattern	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		m (ft)				m (ft)	m (ft)	kPa (psig)	°C (°F)	L abs. (bbl abs.)	m/s (ft/s)	m/s (ft/s)	m/s (ft/s)		mm/y (mpy)	%	
N +2			X1, Y1, Z1 to X2, Y2, Z2	Physical description of the WG-ICDA region boundaries	1												
									Average						Average		
					2												
									Average						Average		
N +3					1												
									Average						Average		
					2												
									Average						Average		
					3												
									Average						Average		

4.6 Final Assessment Site Selection

4.6.1 Once the summary table (i.e., Table 2) has been created for the pipeline segment, the final assessment sites shall be selected. The SME is responsible for identifying the final assessment sites from those locations that have been preselected in accordance with the criteria in Paragraph 4.5.3.

4.6.2 The minimum number of final assessment sites shall be selected in accordance with the criteria established in Table 3. The minimum number of final assessment sites is a function of the pipeline segment length. The SME is responsible for selecting any of the preselected assessment sites locations (listed in the summary table [i.e., Table 2]) to meet the criteria in Table 3.

Table 3
Minimum Number of Final Assessment Sites

Continuous Pipeline Length of All WG-ICDA Regions and Subregions in Pipeline Segment (km) (1 km = 0.62 mi)	Low Wall Loss < 20%	Moderate Wall Loss 21–40%	High Wall Loss 41–60%	Severe Wall Loss > 60%	Minimum Number of Final Assessment Sites per Pipeline Segment
0.1–10.0	0(A) or 1(B)	1	1	1	4
10.1–50.0	1	1	2	2	6
50.1–100.0	1	2	2	3	8
100.1–500.0	1	2	3	4	10
> 500.1	2	3	4	5	14

(A) If the ICPM has already been proven to be reliable, then no detailed examination is required at the assessment site containing a wall loss less than the indicated percentage. ICPM reliability means that it has been validated against detailed examinations for the particular pipeline segment being evaluated.
(B) If the ICPM reliability is uncertain, then at least one detailed examination must be performed at the assessment site with the low wall loss percentage. Model reliability means that it has been validated against detailed examinations for the particular pipeline segment being evaluated.

4.6.2.1 Example. For a pipeline segment 10 km (6 mi) or less in length, Table 3 requires a minimum of four final assessment site locations. The SME is responsible for selecting the four from any of the preselected assessment sites listed in the summary table. There shall be at least one location selected from each wall loss percentage grouping: one assessment site that contains < 20% wall loss; one assessment site that contains 21 to 40% wall loss; one assessment site that contains 41 to 60% wall loss; and one assessment site that contains > 60% wall loss. If one of the wall loss percentage groups is not present, then any other assessment site that contains any other wall loss percentage may be selected.

4.6.2.2 For a pipeline segment 10 km (6 mi) or less in length, if the ICPM results indicate that wall loss percentage values are < 20% wall loss and if the ICPM has been proven to be reliable for the pipeline segment, no assessment sites shall be selected and the pipeline integrity assessment shall be based solely on the ICPM results. On the contrary, if the ICPM has not been proven to be reliable, then one assessment site shall be selected. If wall loss results are dispersed throughout the wall loss percentage groups presented in Table 3, then one assessment site shall selected from each one of the wall loss percentage groups with a minimum of four assessment sites.

4.6.2.3 For instances in which locations have predicted wall losses that do not require a detailed examination, the pipeline operator must perform a detailed examination at the minimum assessment site as required in Table 3. The minimum assessment site is applied to the location with the highest wall loss percentage predicted. The minimum assessment site is also used to validate whether the ICPM is able to predict the measured corrosion rates (see Paragraph 5.2.4).

4.6.3 When the physical location on the pipeline of the final assessment sites are selected, priority shall be given to the following aspects:

4.6.3.1 High-consequence areas or equivalent types of locations in proximity to the public that have an added level of operational risk;

4.6.3.2 Site accessibility, repair history/records, any internal leak/rupture history, low spot areas, etc.;

4.6.3.3 If multiple sites have the same corrosion severity threat for the same internal corrosion mechanism, it may be prudent to perform the first detailed examination at the assessment site that is most easily accessible;

4.6.3.4 More assessment sites may be selected or they may be prioritized by the SME based on any other criterion that has been technically justified and agreed to by the pipeline operator; and

4.6.3.5 Locations selected as final assessment sites should be compared to repair records and historical records to identify any existing steel/composite repair sleeves that would make the detailed examination difficult. Also, because internal corrosion is a time-dependent threat, if the location selected is in an area of replacement pipe, consideration should be given to selecting another assessment site with a similar threat of internal corrosion severity.

4.6.4 A final assessment site selection table shall be constructed.

4.6.4.1 Table 4 shows the final assessment site selection table.

4.6.4.2 Table C2 in Appendix C provides a completed example of a final assessment site selection table.

Table 4
Final Assessment Site Selection

WG-ICDA Region #	WG-ICDA Subregion #	Coordinates	Total Length	Total Elevation	Total Liquid Holdup	Flow Pattern	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)	Comments
			m (ft)	m (ft)	L abs. (bbl abs.)		mm/y (mpy)	%		

4.6.5 Example 2 in Appendix C provides a comprehensive example of how the process from WG-ICDA region identification to final assessment site selection is performed.

Section 5: Step 3—Detailed Examination

5.1 Introduction

5.1.1 The objectives of the WG-ICDA *detailed examination step* are to:

(a) Determine whether the predicted internal corrosion exists at assessment sites selected;

(b) Quantify the actual amount of damage by means of NDE techniques; and

(c) Use the findings to assess the overall integrity of the WG-ICDA region.

5.1.2 The *detailed examination step* (see Figure 3) focuses the detailed examination efforts on the final assessment sites selected in the *indirect inspection step.*

5.1.3 Detailed examination of assessment sites shall be based on the detailed examination process diagram, as shown in Figure 3. Any deviation from this process must be technically justified by the pipeline operator, and the reasons documented.

5.1.4 Procedures for NDE and subsequent action as a result of identifying indications found during the detailed examination are not included in the scope of this standard. The pipeline operator must follow appropriate guidelines (see Paragraph 1.1.12) for evaluating each assessment site for and responding to the presence and severity of internal corrosion at each assessment site examined.

5.2 Detailed Examination Process

5.2.1 At least the minimum number of final assessment sites selected in the *indirect inspection step* shall be exposed for detailed examination.

5.2.2 Detailed examination of each selected assessment site must be sufficient to identify and characterize the internal corrosion features in the pipe being assessed.

5.2.2.1 The pipeline operator shall measure and record details of the wall thickness for a grid pattern sufficient to determine the axial length and width (to a tolerance of twice the nominal wall thickness [i.e., ± 2t]) of those wall loss indications present. The length of the pipeline affected by water accumulation may be large in some situations, and care should be taken in selecting a suitable NDE method. Remaining wall thickness values must be periodically recalibrated at the assessment site.

5.2.2.2 The NDE method or combination of methods used for detailed examinations shall quantify the amount of wall loss. NDE methods used to determine the remaining wall thickness of the pipe in corroded areas shall be performed in accordance with qualified written procedures that are approved by the pipeline operator, in accordance with applicable standards, and performed by individuals certified by training and qualified by experience.

5.2.3 Once the detailed examinations have been performed, the integrity of the pipeline at the assessment site shall be evaluated using the following criteria. These criteria are the basis for determining the number of detailed examinations required.

5.2.3.1 Internal corrosion metal loss is considered significant if the remaining wall thickness of the pipe cannot support the internal pressure as specified in RSTRENG or ASME B31G.

5.2.3.1.1 The pipeline operator shall evaluate or calculate the remaining strength of the pipe at locations where corrosion is found. Example methods of calculating the remaining strength include ASME B31G, RSTRENG, and Det Norske Veritas (DNV)[(6)] Recommended Practice DNV-RP-F101.[16]

5.2.3.1.2 This criterion requires scheduled maintenance or repair in accordance with ASME B31.8S. An assessment site shall be considered active (kept exposed or open) if the remaining wall thickness of the pipe is less than 80% of the specified nominal wall thickness (i.e., wall loss is greater than approximately twice the nominal wall thickness tolerance allowed in API 5L) until the proper repair or mitigation actions have been performed.

5.2.3.2 A pipeline-specific analysis may be performed to develop criteria for significant internal corrosion. The analysis may include consideration of previous metal loss and the number of years of pipeline service.

5.2.3.3 Other technical criteria for significant corrosion may be used with documented technical justification.

5.2.4 If the ICPM results are corroborated (within ± 10% of actual wall loss) by the detailed examinations, further assessment site exposures may not be necessary at the discretion of the SME. If, on the contrary, the ICPM results are not corroborated by the detailed examinations (exceed ± 10% of actual wall loss), all minimum assessment sites shall be exposed and the ICPM adjusted and/or reassessed.

5.2.5 At the discretion of the pipeline operator, additional validation examinations to validate the ICPM may be performed in WG-ICDA regions in which the detailed examination process has been completed.

5.2.6 When the detailed examination process identifies the existence of extensive severe internal corrosion that has not been predicted by the *indirect inspection step,* the pipeline operator shall return to the preassessment step and reevaluate all the information obtained, because the applicability of WG-ICDA is in question.

5.2.7 The detailed examination procedures, wall thickness data, and remaining strength calculations must be retained with the WG-ICDA records for the life of the pipeline.

5.3 Other Facility Components

5.3.1 In some cases, drips or other facility components may serve as convenient locations for detailed examination.

5.3.2 If the fixture geometry restricts evaporation of water, it is possible for corrosion to be more severe inside the fixture. Therefore, the pipeline operator shall examine at least one fixture where water can be trapped in a low-priority WG-ICDA region. This may also be used as a validation site to validate the ICPM.

5.4 Assessment Site Exposure

5.4.1 Once an assessment site has been exposed, and before it is given clearance (onshore and offshore), the pipeline operator may consider the installation of a corrosion monitoring device (e.g., coupon, ER probe, linear polarization resistance [LPR] probe, or electrochemical noise [EN] sensor). This allows a pipeline operator to benefit from long-term monitoring in a location most susceptible to corrosion and confirm assessment intervals.

5.4.1.1 Corrosion monitoring devices installed at arbitrary locations (e.g., beginning of pipeline) shall be avoided.

[(6)] Det Norske Veritas (DNV), Veritasveien 1, 1363, Høvik, Oslo, Norway.

5.4.1.2 Assessment sites for detailed examination identified through the WG-ICDA process facilitate a more representative placement of the corrosion monitoring device.

5.4.2 ILI tool (or other indirect inspection tool) results for an upstream portion of the pipeline within a WG-ICDA region may provide helpful information for the assessment of conditions in a downstream portion of the pipeline where an intelligent pig cannot be run.

5.4.2.1 Because WG-ICDA evaluates corrosion severity based on a variety of parameters such as flow, corrosive species, and mitigation factors, any integrity determination shall be performed at locations of minimum acceptable corrosion.

5.4.2.2 Use of ILI data for detailed examination must be supplemented by assessment site exposure and detailed examination consistent with the high-priority assessment sites identified in the indirect inspection step of WG-ICDA.

5.4.3 If a pipeline operator using WG-ICDA determines that assessment sites are free from metal loss, then the integrity of these WG-ICDA regions has been ensured relative to this internal corrosion threat. In this case, resources may be refocused on those WG-ICDA regions where internal corrosion is determined to be more likely.

Section 6: Step 4—Postassessment

6.1 Introduction

The objectives of the *postassessment step* (see Figure 4) are to validate the WG-ICDA process, assess the effectiveness of WG-ICDA, and determine reassessment intervals.

6.2 Validation of the Process

WG-ICDA is a continuous improvement process. Through successive WG-ICDA applications and the integration of operational data, a pipeline operator should be able to identify and address locations at which corrosion activity has occurred, is occurring, or may occur in the future (i.e., MPLs).

6.3 Assessment of WG-ICDA Effectiveness

6.3.1 Effectiveness of the WG-ICDA process is determined by correlation between corrosion identified by detailed examination and the ICPM prediction at those locations.

6.3.1.1 The pipeline operator must evaluate performance effectiveness of WG-ICDA. The process shall be documented.

6.3.1.2 Improvements as a result of this assessment shall be continually incorporated into future WG-ICDA integrity assessments.

6.3.2 If extensive corrosion is found throughout the pipeline segment or corrosion is found in areas that were not determined to be a priority or, on the contrary, no corrosion is found in areas that were determined to be a priority, WG-ICDA has not been effective and the pipeline operator should use other means of integrity assessment.

6.4 Determination of Reassessment Intervals

6.4.1 WG-ICDA reassessment intervals shall be determined using the method described in Paragraph 6.4.1.1.

6.4.1.1 When internal corrosion is identified during detailed examinations, the maximum reassessment interval for each WG-ICDA subregion shall be taken as one-half of the calculated remaining WG-ICDA subregion life.

6.4.1.2 Over time, the procedures described in Paragraphs 6.4.2 through 6.4.5 may be used as feedback to update or optimize the reassessment interval.

6.4.2 The selected method(s) of setting reassessment intervals must be technically justified, validated by the pipeline operator, and must meet the approval of the local jurisdictional pipeline regulator.

6.4.3 Reassessment intervals shall never exceed the calculated remaining life of the pipeline segment.

6.4.4 The distribution and uncertainty of predicted corrosion rates must be considered.

6.4.5 The success of the ICPM is based on the visual confirmation of damage and the wall loss being within ± 10% of the actual damage measured, with the range not to exceed 20%. For example, if the actual worst-case wall loss damage was found to average 54% over several WG-ICDA subregions and the "corrected" wall loss predicted values were 46% on average for the same specific WG-ICDA subregions with that level of damage, then the ICPM and the WG-ICDA process have been confirmed to be valid.

Section 7: Records

7.1 Introduction

This section describes the WG-ICDA records that document data in a clear, concise, and workable manner and are pertinent to the *preassessment, indirect inspection, detailed examination, and postassessment steps* of the WG-ICDA process. All decisions and supporting assessments must be fully documented. The records required by this standard should be kept for the life of the pipeline.

7.2 Preassessment

All *preassessment step* actions and decisions shall be recorded. They include, but are not limited to, the following:

7.2.1 Data elements collected for the pipeline segment to be evaluated in accordance with Paragraph 3.2;

7.2.2 Methods and procedures used to integrate data collected to determine when indirect inspection tools can and cannot be used; and

7.2.3 A technical and thorough document supporting the WG-ICDA region identification boundaries, their complete description, and physical characteristics.

7.3 Indirect Inspection

All *indirect inspection step* actions and decisions shall be recorded. These include, but are not limited to, the following:

7.3.1 Geographically referenced locations of the beginning and ending point of each WG-ICDA region and WG-ICDA subregion and each fixed point (monument) used for determining the accuracy of each measurement;

7.3.2 Procedures for determining accuracy of elevation profiles;

7.3.3 Methodology, including real and assumed data, used to identify and prioritize areas that may be susceptible to internal corrosion and may be selected as assessment sites; and

7.3.4 Data used to record or estimate flow, compositions, corrosion growth rates, operations, mitigation, and internal corrosion prevention decisions.

7.4 Detailed Examination

All *detailed examination step* actions and decisions shall be recorded. These include, but are not limited to, the following:

7.4.1 Data collected before and after assessment site evaluation, measured metal-loss corrosion geometries, techniques used, and reported records;

7.4.2 Planned mitigation activities; and

7.4.3 Descriptions of and reasons for selections of additional assessment sites, validation sites to validate the ICPM, or reprioritizations.

7.5 Postassessment

All *postassessment step* actions and decisions shall be recorded. These may include, but are not limited to, the following:

7.5.1 Maintaining safety through remaining-life calculation results;

7.5.1.1 Maximum remaining defect size determinations;

7.5.1.2 Corrosion growth rate determinations;

7.5.1.3 Method of estimating remaining life;

7.5.1.4 Results of remaining strength calculations;

7.5.2 Reassessment intervals, including technical justification and pipeline operator validation of the selected method of reassessment, and any scheduled activities;

7.5.3 Criteria used to assess WG-ICDA effectiveness and results from assessments;

7.5.3.1 Criteria and metrics;

7.5.3.2 Data from periodic assessments;

7.5.4 Monitoring Records;

7.5.4.1 Feedback; and

7.5.4.2 How results were incorporated for continuous improvement.

References

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2. ANSI/NACE SP0208 (latest revision), "Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines" (Houston, TX: NACE).

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5. ANSI/ASME B31.8 (latest revision), "Gas Transmission and Distribution Piping Systems" (New York, NY: ASME).

6. ANSI/ASME B31.8S (latest revision), "Managing System Integrity of Gas Pipelines" (New York, NY: ASME).

7. ANSI/API 1160 (latest revision), "Managing System Integrity for Hazardous Liquid Pipelines" (Washington, DC: API).

8. ANSI/API 579-1/ASME FFS-1 (latest revision), "Fitness-for-Service" (Washington, DC: API).

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Appendix A
Factors Influencing Corrosion Severity
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

To prioritize assessment sites for detailed examination, the overall cumulative damage (alternatively risk) in each can be evaluated numerically. The corrosion severity-influencing factors must be known or estimated so their values can be numerically assigned based on the significance of their influences either by calculation using well-established software tools, if available, or by a SME's technical judgment. For a reliable estimate of influencing factors, the corrosion mechanisms need to be accurately defined to determine individual effects on corrosiveness within a WG-ICDA subregion. Some ICPMs may be capable of assessing these parameters within their protocols to yield their respective corrosion rate data. A general description of these corrosion severity factors are provided in this appendix.

A1 Corrosion Mechanisms Resulting from Gas Quality

A1.1 Background

Gas quality specifications are set for commercial and contractual considerations, which include preventing corrosion, preventing blockages from freezing hydrate formation, and ensuring the heating value of the natural gas. Gas quality requirements differ between companies and sometimes business units, and no industry standard currently exists to address this issue. A review of tariff gas composition specifications pertinent to corrosive gas constituents showed that CO_2 varied from 0.8 to 4 percent, H_2S from 4 to 16 ppm, and O_2 from a few ppm to 1 mole percent. The actual concentrations of some of these constituents are seldom measured. Of the 106 node points of gas transactions recently surveyed, only 10 nodes reported measured O_2 concentration, which ranged from 20 to 5,800 ppm. These corrosive species directly influence the pipeline internal corrosion rate.

In the case of wet gas lines and gathering lines, the CO_2 and H_2S levels may vary widely, beyond the above ranges.

A1.2 Effect of Dissolved CO_2 and H_2S

The corrosion rate of steel in carbonic acid (H_2CO_3) is greater than in hydrochloric acid (HCl) for the same solution pH. The reason is that H_2CO_3 itself can be reduced at the steel surface to form hydrogen. The presence of CO_2 and H_2S definitely increases the pipeline corrosion rate. In the operating temperature range, ferrous carbonate ($FeCO_3$) and ferrous sulfide (FeS) are likely to precipitate and have an effect on the local corrosion rate. Research shows that CO_2 hydration can be a slow homogeneous reaction and limits the corrosion process. Steel corrosion caused by dissolved CO_2 and H_2S is a complex phenomenon and has been studied extensively.[17–28] Depending on gas quality, H_2S may be beneficial or detrimental to the pipeline corrosion. Too little or too much H_2S can increase the corrosion rate, while in a middle range of concentration, the formation of FeS is passive and can decrease the corrosion rate. When there is too much H_2S, the passivity of FeS is saturated at the steel surface, while as H_2S content increases, the solution pH decreases and the corrosion rate increases. NACE MR0175/ISO 15156[29] provides information for other H_2S corrosion mechanisms.

With dissolved CO_2 and H_2S, the solution is acidic. Too little H_2S content may not result in formation of FeS, even though FeS has much lower solubility than $FeCO_3$. A molar ratio of CO_2 to H_2S exists in the gas phase at which the precipitate exchanges between FeS and $FeCO_3$. This CO_2/H_2S ratio was determined theoretically to be approximately 1,400;[30,31] it has been found experimentally that this CO_2/H_2S ratio is approximately 500.

- If the CO_2/H_2S ratio is greater than 500, the corrosion products tend to be $FeCO_3$, and the corrosion mechanism is very much like CO_2 corrosion alone. H_2S would have little impact on the corrosion severity.

- If the CO_2/H_2S ratio is less than approximately 20, the corrosion products are FeS which, if undamaged, would reduce corrosion to a very low level. However, in the presence of high chloride (Cl^-) (greater than 10,000 ppm), elemental sulfur, O_2, sludge, or if the flow regime is either slug or stagnant, or if the concentrations of some mitigating corrosion inhibitors are not sufficient, FeS scale can break down locally, resulting in very severe pitting corrosion at a rate several times greater than the CO_2 corrosion rate.

- If the CO_2/H_2S ratio is between 20 and 500, both $FeCO_3$ and FeS can coexist. Research is still in progress for this mixed corrosion mechanism.

A1.3 Effect of Dissolved O_2

Dissolved O_2 likely increases the corrosion rate, and the corrosion rate is diffusion limited. Although O_2 reduction at the steel surface can generate a hydroxide ion or increase the local pH and potentially decrease the hydrogen ion and water reduction rates, overall, the increase of steel corrosion dominates. This increase in corrosion rate caused by O_2 can be approximated by the O_2 diffusion limited current density.[26,30,32] Oxygen can act synergistically with other corrosion mechanisms.

A2 Effect of Operations Upsets

An upset, caused by design or accidents, results in a change of fluid flow, fluid chemistry, and possibly a pipeline internal surface condition. These all potentially influence pipeline corrosion. Upsets occur mainly during start-up (commissioning), temporary shutdowns, restarts, or plant turnaround. In contrast to steady-state or normal operations, these processes result in dynamic changes of the operation.

A2.1 Change of Fluid Flow

At start-up, the operation is non-steady-state for a period of time. During temporary shutdown and plant turnaround, the liquids stagnate at low spots. Upon restart, either the gas flow cannot move all the settled liquids or it can result in slug flow (where applicable) when it empties the liquids. Temporary production surge or decline can also affect the fluid flow.

A2.2 Change of Fluid Chemistry

During start-up, the initial well bore self-cleaning may result in higher salinity, and higher contents of the total suspended solids (TSS) in the produced effluents. The inhibitors may be adsorbed by the very large overall surface of the fine silts and solids produced, leaving less inhibitor available to protect the pipe surface. In effect, the solids become "sites" for diminishing inhibitor performance and perhaps even for accelerating corrosion. Also, the high salinity may exceed the operating envelope of the inhibitor.

During temporary shutdowns or plant turnaround, the settling of solids including sulfur may lead to underdeposit corrosion. If the pipeline is opened, admission of air/moisture increases the likelihood of corrosion. The change of flow resulting from upsets also varies the corrosion condition.

During well workover, the introduction of low pH fluids or fluids with higher chloride levels (if HCl is used) also increases the severity of corrosion.

The introduction of a foreign substance into the pipeline by design or by accident, such as (1) methanol/ethanol/glycol injection for hydrate control; (2) O_2 ingress caused by vapor phase recovery operations and negative pressure seals for compressors; (3) dehydrator upsets (for wet pipelines with tie-ins that may have a dehydrating unit); and (4) microbial activity (sulfate-reducing bacteria [SRB] or acid-producing bacteria [APB]), all increase the likelihood of corrosion.

During hydrostatic testing, if the water was not properly treated, it may induce internal corrosion as well as bacteria growth. If the pipe is not completely dried before it enters into operation, corrosion may continue.

A2.3 Change of Pipeline Internal Surface Condition

During start-up, the original surface of the pipeline possibly covered by mill scale (mainly oxides or hydrated oxides) may be converted to $FeCO_3$ or FeS as a result of corrosion caused by the acid gas, CO_2, or H_2S. The passivity of the mill scale may thus be lost.

If the pipeline is opened for inspection/repair, or is opened during temporary shutdowns or plant turnaround, moist air may be introduced, and existing scales may be converted to hydroxides.

A temporary production surge or decline also affects fluid flow and the pipeline internal surface condition.

During a period of suspended pipeline operation, the pipeline may be blanketed with field fuel gas containing acid gas contents different from the previously produced effluents. Scales previously established on the pipe wall may be converted into a different one and may not offer the same corrosion resistance when the pipeline is recommissioned.

During well workover, low pH fluids or higher chloride levels (if HCl is used) can weaken/destabilize the previously protective scales.

Consideration shall be taken for liquid holdup or traps at fittings or design locations such as low points and drips.

A3 Other Factors that Contribute to Internal Pipeline Corrosion

A3.1 Effect of Bacteria

MIC occurs when a unique combination of biological factors is present simultaneously with other conditions, such as specific regimes of water chemistry, temperature, flow velocity, metallurgy, and organic and inorganic fouling materials. The biological factors involve growth of microorganisms that induce or initiate the corrosion mechanism. There are two types of organisms:

A3.1.1 Planktonic Organisms

Free-floating bacteria are commonly referred to as planktonic organisms, but depending on the type of system, may also include unattached algae, diatoms, fungi, and other microorganisms that may be present in bulk fluids. In most cases, it is planktonic bacteria that are the focus of monitoring for MIC, because system fluids are generally easier to sample than metallic surfaces. Unfortunately, the levels of planktonic bacteria present in the liquids are not always indicative as to whether MIC occurs or, if so, to what extent. At best, detection of viable planktonic bacteria serves only as an indicator that living microorganisms are present in a particular system. Some of the organisms may be capable of participating in microbial attack of materials. In some cases, monitoring for planktonic organisms can be misleading. For example, following biocide application, elimination or reduction of viable planktonic organisms imply to many pipeline operators a successful treatment program, whereas, in reality, attached organisms may be unaffected by the biocide treatment and may be able to continue their attack of the metal surfaces.

A3.1.2 Sessile Organisms

Microorganisms that are attached to a surface are called sessile organisms. Bacteria and other microorganisms are almost always present as a consortium or community of organisms, collectively referred to as a biofilm. Because MIC occurs directly on metal surfaces, sessile organisms are the ones that are most representative of potential problems and, therefore, are an important component to monitor. Monitoring sessile organisms requires either that the system or pipeline be regularly opened for sampling or that accommodations be made in the system design to allow for regular collection or online tracking of attached organisms during operation. Sessile bacteria can change the chemistry of the solution near the steel surface and therefore change the corrosion rate. The effects of bacteria as a function of distance can be difficult to predict. A pipeline known to be affected by MIC is expected to possibly have a higher corrosion uncertainty. If MIC is considered an important mechanism, added assessment sites may be necessary.

A4 Effect of Liquid Hydrocarbons

Liquid hydrocarbons can decrease the corrosion rate by entraining or emulsifying water. If water is dispersed within the hydrocarbon phase, the corrosion rate is expected to be lower than if it is directly in contact with the pipe wall.

If hydrocarbons condense along a pipeline segment, resulting in an increase in its ratio to water, it is possible that corrosion is less likely at downstream locations. This is particularly true if liquid water dominates upstream.

Some hydrocarbons may decrease the corrosion rate by inhibition mechanisms similar to inhibitors. The inhibitor efficiencies can depend on the water to hydrocarbon ratio.

If water is emulsified in a continuous hydrocarbon phase and if this emulsion can break over distance, free liquid water may form. If the flow regime is stratified, liquid water may drop to the pipe bottom to increase the likelihood of corrosion downstream. This effect may be less with slug or annular flow regimes because the liquid phases are mixed.

A5 Effect by the Presence of Solids

Pipelines may contain accumulations of solids, sludge, biofilm/biomass, or scale. They are carried into a pipeline segment, precipitate from the liquids, and grow on the pipe wall. Sources of solids include corrosion products (e.g., $FeCO_3$ and FeS), other inorganic scales (e.g., calcium carbonate and barium sulfate), organic scales (e.g., paraffins and asphaltenes), and carryover of solids into the pipeline segment, including silicates (e.g., formation sand). They can have several effects on corrosion. Scales primarily affect the transport of materials to (or from) the pipe wall, the surface solution chemistry, and the kinetics of the electrochemical reactions. They may also affect flow characteristics, if a sufficiently large volume of solids exists to reduce the effective pipe diameter. Their presence in a pipeline may increase the corrosion rate by retaining water because of their hygroscopic properties or deliquescence, or by the formation of a concentration cell or crevice corrosion under the deposit. They can decrease the rate of corrosion if they form an intact protective barrier layer. Their presence also increases the likelihood for bacteria growth.

Underdeposit corrosion, however, occurs at lower flow conditions. Below a minimum flow velocity in a horizontal pipeline (or below critical angles in inclined pipelines), sand particles in the fluid can form a bed on the bottom of the line. As the sand is produced, a sand bed builds up until the increased velocity above the bed is large enough to transport the particles farther down the pipeline where they settle, resulting in the increase in the length of the sand bed. Deposition of the sand, especially in smaller-diameter pipelines, can lead to partial or complete blockage of the pipelines, enhanced underdeposit corrosion, and MIC. Failure frequencies of smaller-diameter pipelines (typically 25 to 50 mm [1 to 2 in] in diameter) operating at lower pressures (typically less than 700 kPa [100 psi]), and velocities (typically less than 2 m/s [7 ft/s]), have been observed. Whether sand deposits or not depends on pipe diameter, inclination, expansion, and flow rate. Empirical equations to predict conditions for the deposition of solids are available.

A6 Effect of Fluid Hydrodynamics and Flow Behavior

The flow parameters can have a significant effect on the corrosion rate, because they change the convective transport of solution species and the pipe surface condition. Diffusion of ionic species to and from the pipeline surface ultimately governs dissolution of the pipe wall, but flow regime is intimately related to the diffusional processes governing corrosion. A pipeline with similar flow parameters (e.g., flow regime and velocity) may have corrosion distribution determined only by non-flow-related corrosion severity factors (e.g., gas quality, inhibitors). A pipeline with more than one flow regime over a distance can have corrosion distribution affected by the flow regime and mass transfer processes.

Considered as secondary, the flow effects on corrosion can differ within one flow regime. For example, an area identified as slug flow does not reflect the slug frequency or severity. Similarly, defining an area as stratified does not discriminate between wavy and smooth. Defining an area as annular flow does not consider film velocity or the amount of mist. In terms of condensing water in locations of high heat loss, it may be considered as an additional influence on corrosion when it occurs with the stratified flow regime. This effect on top-of-line corrosion is less important for pipe containing slug or annular flow.

A7 Effect of Corrosion Inhibitors

The manner in which chemical treatment is applied may result in a nonuniform effectiveness along a pipeline length. Both selection and application of corrosion inhibitors are important. Standards are available to select corrosion inhibitors, including ASTM G170,[33] ASTM G184,[34] and ASTM G185.[35]

It is not only important to select the proper corrosion inhibitor, but also to ensure that the inhibitor is applied properly. Laboratory conditions are carefully controlled, and very sensitive measurement techniques may be used. These may indicate extremely low inhibited corrosion rates that yield very high inhibitor efficiencies. In practice, such low corrosion rates are not achievable in the field. The requirement of a corrosion inhibitor is to reduce the corrosion rate to that used for the design of the facility. This focus is often lost when inhibitor efficiency is discussed. High inhibitor efficiency does not always ensure that the design corrosion rate is met. It assumes that throughout the life of the pipeline operation, the availability of the inhibitor is 100%, whereas the availability is defined as the fraction or percentage of time that the inhibitor is applied at the correct dosage. In many cases, this has proved to be the weakest link for a corrosion inhibitor application. Delivery issues, pump problems, and poor communications regularly mean that the inhibitor is either switched off or not at the required dosage.

Appendix B
Internal Corrosion Prediction Models
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

An ICPM can be used to identify locations for detailed examination instead of determining the probability of corrosion distribution. Several ICPMs for oil and gas pipelines are presented in this appendix. This list is not exhaustive. For example, several other commercial and noncommercial software packages are available.

Anderko Model[36–38]

This comprehensive model has been developed to calculate the corrosion rates of carbon steels in the presence of CO_2, H_2S, and brine. It combines a thermodynamic model (that provides realistic speciation of aqueous systems) with an electrochemical model (based on partial cathodic and anodic processes on the metal surface). The partial processes taken into account by this model include the oxidation of iron and reduction of hydrogen ions, water, H_2CO_3, and H_2S.

Crolet Model[39,40]

The Crolet model predicts the probability of corrosion in oil wells. It is based on a detailed analysis of field data on CO_2 corrosion from two oilfield operations. In the Crolet model, the parameters that influence potential corrosion severity are pH level, H_2CO_3, CO_2, acetic acid (CH_3COOH), temperature, and flow rate.

Dayalan Model[17]

This model consists of a computational procedure and a computer program to predict the corrosion rates of a carbon steel pipeline caused by CO_2-containing flowing fluids in oil and gas field conditions. The computational procedure is based on a mechanistic model for CO_2 corrosion and is developed from basic principles. The model takes into account the CO_2 corrosion mechanism and the kinetics of electrochemical reactions, chemical equilibrium reactions, and mass transfer.

De Waard and Milliams Model[18–20]

The model developed by de Waard and Milliams is the most frequently cited model in evaluating internal corrosion. The first version of this model was published in 1975, and it has been revised three times since then. In the earlier versions of the model, there was no significant consideration of the effects of liquid flow velocity on the CO_2 corrosion rate. The corrosion reaction was assumed to be activation controlled, although the observed corrosion rates were, in some cases, about twice the rate predicted. Therefore, a somewhat empirical equation was developed to describe and predict the effect of flow rate.

Garber, Adams Model[41]

The Garber, Adams model, developed from the operating conditions of condensate wells, can be used to predict corrosion rates in gas condensate wells based on operating conditions, temperatures, and flow rates.

Mishra Model[42]

Corrosion of steel in CO_2 solutions is considered to be a chemical-reaction-controlled process. In the Mishra model, a corrosion rate equation was derived on the basis of fundamental reaction rate theory and was then compared with empirically determined relationships reported in the literature. The prediction of this model is similar to the empirically developed models; the model, however, accounts for the effects of steel microstructure and the flow velocity of the solution on the corrosion rate. The application limit for this model occurs when the corrosion process begins to be diffusion controlled, usually after the formation of a stable corrosion product scale on the steel surface.

Nesic Model[43–45]

Nesic uses a theoretical approach by modeling individual electrochemical reactions occurring in a water-CO_2 system. The processes modeled in this system are the electrochemical reactions at the metal surface and the transport processes of all the species in the system, including hydrogen ion (H^+), CO_2, H_2CO_3, and ferrous ion (Fe^{2+}). The Nesic model requires the following inputs: temperature, pH, CO_2 partial pressure, oxygen concentration, steel, and flow geometry. Version 2 of the Nesic model predicts the equivalent of a scaling tendency (that is, the ratio between the precipitation rate and the corrosion rate).

Nyborg Model[46]

Nyborg integrated the 1993 and 1995 versions of the de Waard and Milliams model with a commonly used three-phase fluid-flow model. The temperature, pressure, and liquid flow velocity profiles derived from this fluid-flow model are used to calculate CO_2 partial pressure, pH, and corrosion rate profiles along the pipeline.

NORSOK Model[47]

This model is an empirical corrosion rate model for carbon steel in water containing CO_2 at different temperatures, pH, CO_2 fugacities, and wall shear stresses. It is based on flow-loop experiments at temperatures from 5 to 160 °C (41 to 320 °F). A large amount of data at various temperatures, CO_2 fugacities, pH, and wall shear stresses are used.

Palacios and Dutta-Roy Model[48–51]

This is a process hydraulics algorithm for multiphase flow modeling combined with corrosion models based on the 1995 de Waard and Milliams correlation. It includes correction factors that correlate with seven years of field data from different oil fields around the world.

Papavinasam Model[52,53]

This model predicts internal pitting corrosion of oil and gas pipelines. The model accounts for the statistical nature of the pitting corrosion, predicts the growth of internal pits based on the readily available operational parameters from the field, and includes the pit growth rate driven by variables that are not included in the model. It also considers the variation of the pitting corrosion rate as a function of time and determines the error in the prediction.

Pots Model[54]

This mechanistic model predicts the CO_2 corrosion rate and the effects of fluid flow. The model, also referred to as the limiting corrosion rate (LCR) model, provides a theoretical upper limit for the corrosion rate based on the assumption that the rate determining steps are the transport and production of protons and H_2CO_3 in the diffusion and reaction boundary layers.

Smith and de Waard Model[55]

This model consists of a computational procedure based on de Waard and Milliams correlation and a computer program to predict the corrosion rates of a carbon steel pipeline caused by CO_2-containing flowing fluids in oil and gas field conditions.

Srinivasan Model[56]

The basis of the Srinivasan model is the de Waard and Milliams relationship between CO_2 and corrosion rate, but additional correction factors are introduced. The first step in this approach is a computation of the system pH. The dissolved CO_2 (or H_2S) that contributes to pH is determined as a function of acid gas partial pressures, bicarbonates, and temperature. In addition to pH reduction, the Srinivasan model takes into account the role of H_2S as a general corrodent, as a protective film former, and as a pit initiator.

Teevens Model[32,57]

This mass transfer model is capable of yielding a general corrosion rate for uninhibited corroding multiphase or two-phase pipeline systems, in which O_2, CO_2, and H_2S contribute to corrosion of carbon steel pipes. The gas-liquid flow model was updated mainly from the work of Petalas and Aziz,[58] Taitel and Dukler,[59] and Barnea.[60] The flow model predicts the flow pattern, liquid holdup, pressure drop, and friction losses and calculates gas and liquid velocities.

Multiphase Flow and Liquid Holdup Correlations

Multiphase flow correlations generally fall into two broad classifications (empirical and mechanistic), although there is considerable overlap between the two. Empirical correlations, which were prevalent in the 1970s and 1980s, depend on combining physical principles with regression analyses of data generated in test loops that generally should be scaled up to represent real-world conditions. Mechanistic correlations rely more on first principle physics, supplemented with test loop data, primarily for closure relationships. Some literature is available on these two classifications.[60–83]

Appendix C
Examples of WG-ICDA Region and Subregion Identification, and Assessment Site Selection
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

EXAMPLE 1—WG-ICDA REGION AND SUBREGION IDENTIFICATION[84]

Figure C1 shows an example of a pipeline segment that was assessed. In accordance with Paragraph 3.4, a pipeline segment (identified as Pipeline Segment A-B of length X) was defined from a compressing station (A) to a gas treatment plant (B).

WG-ICDA Region Identification

Using the criteria in Paragraph 3.5, three steps can be followed by the pipeline operator to identify the WG-ICDA regions:

Step 1: Identify the "must" parameters within the pipeline segment (see Paragraph 3.5.1), and then identify individual WG-ICDA regions accordingly.

- All inputs and withdrawals of process fluids along the pipeline segment; and
- Areas along the pipeline segment that have been subjected to bidirectional flow.

Step 2: Identify the "optional" parameters within the pipeline segment (see Paragraphs 3.5.1.1 through 3.5.1.3), and then identify individual WG-ICDA regions accordingly.

- Unit operation changes;
- Location of chemical injection points; and
- Location of valves, appurtenances, and/or pig traps.

Step 3: Superimpose all the individually identified WG-ICDA regions from Steps 1 and 2 into as many resulting WG-ICDA regions for this pipeline segment.

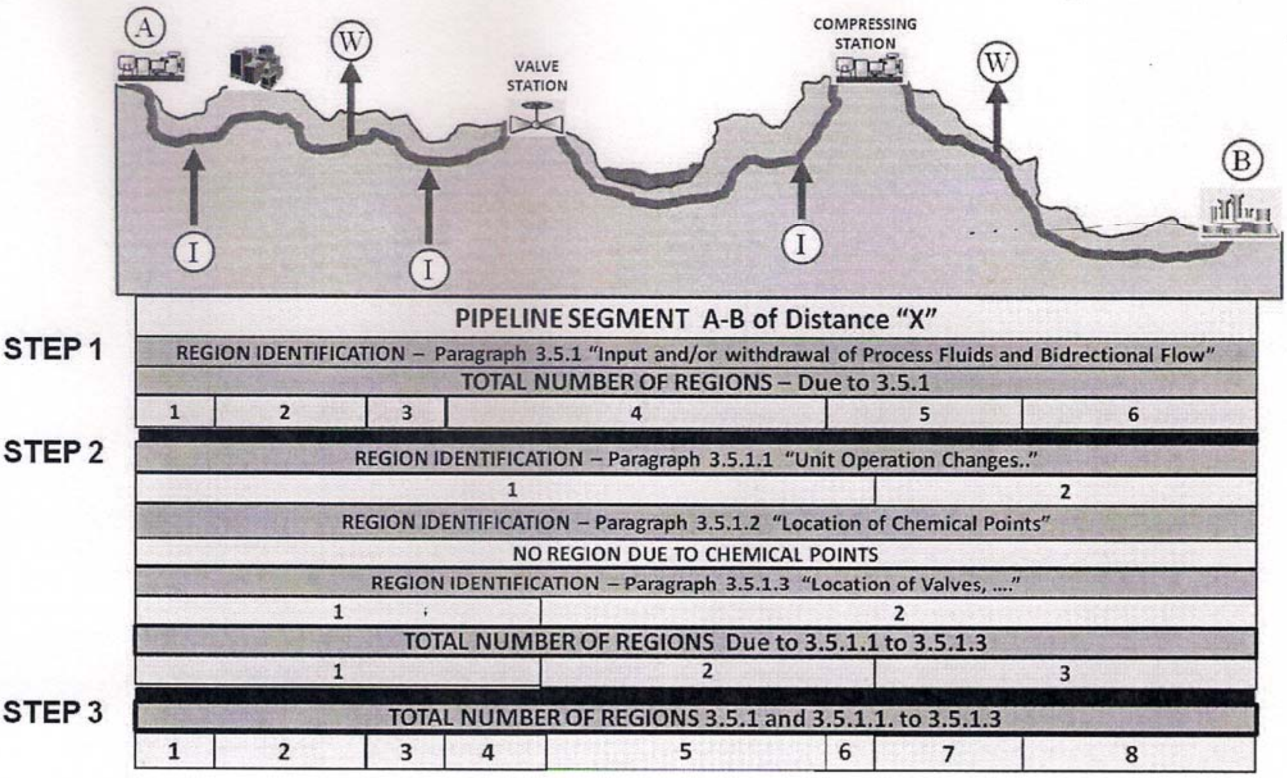

Figure C1: WG-ICDA region identification for an idealized example.

In this example, which is also illustrated in Figure C1, the pipeline operator uses the three steps as follows to identify the WG-ICDA regions within Pipeline Segment A-B.

Step 1: Identify the "must" parameters, and then identify individual WG-ICDA regions accordingly.

Inputs (I) = 3
Withdrawals (W) = 2
Areas of bidirectional flow = 0

In this step, six individual WG-ICDA regions were identified.

Step 2: Identify the "optional" parameters, and then identify individual WG-ICDA regions accordingly.

Unit operation = 1 (intermediate compressing station) Two WG-ICDA regions were identified.

Chemical injection points = 0 No WG-ICDA regions were identified.

Valves, appurtenances, pig traps = 1 (valve station) Two WG-ICDA regions were identified.

In this step, three individual WG-ICDA regions were identified.

Step 3: Superimpose all the individually identified WG-ICDA regions from Steps 1 and 2 into as many resulting WG-ICDA regions for this pipeline segment.

In this step, eight WG-ICDA regions were identified for Pipeline Segment A-B.

WG-ICDA Subregion Identification

WG-ICDA subregions are identified (see Paragraph 4.3) from the results of the multiphase flow modeling (see Paragraph 4.2) and as a function of the flow patterns present within the WG-ICDA region.

Flow patterns are developed as a result of the hydrodynamic interaction between the gas and the liquid as they flow through a pipeline and thus are dependent on the superficial gas and liquid velocities. Within a WG-ICDA region, different flow patterns may develop, which create the WG-ICDA subregions. Examples of the different flow patterns that can occur in a horizontal pipeline are shown in Figure C2.

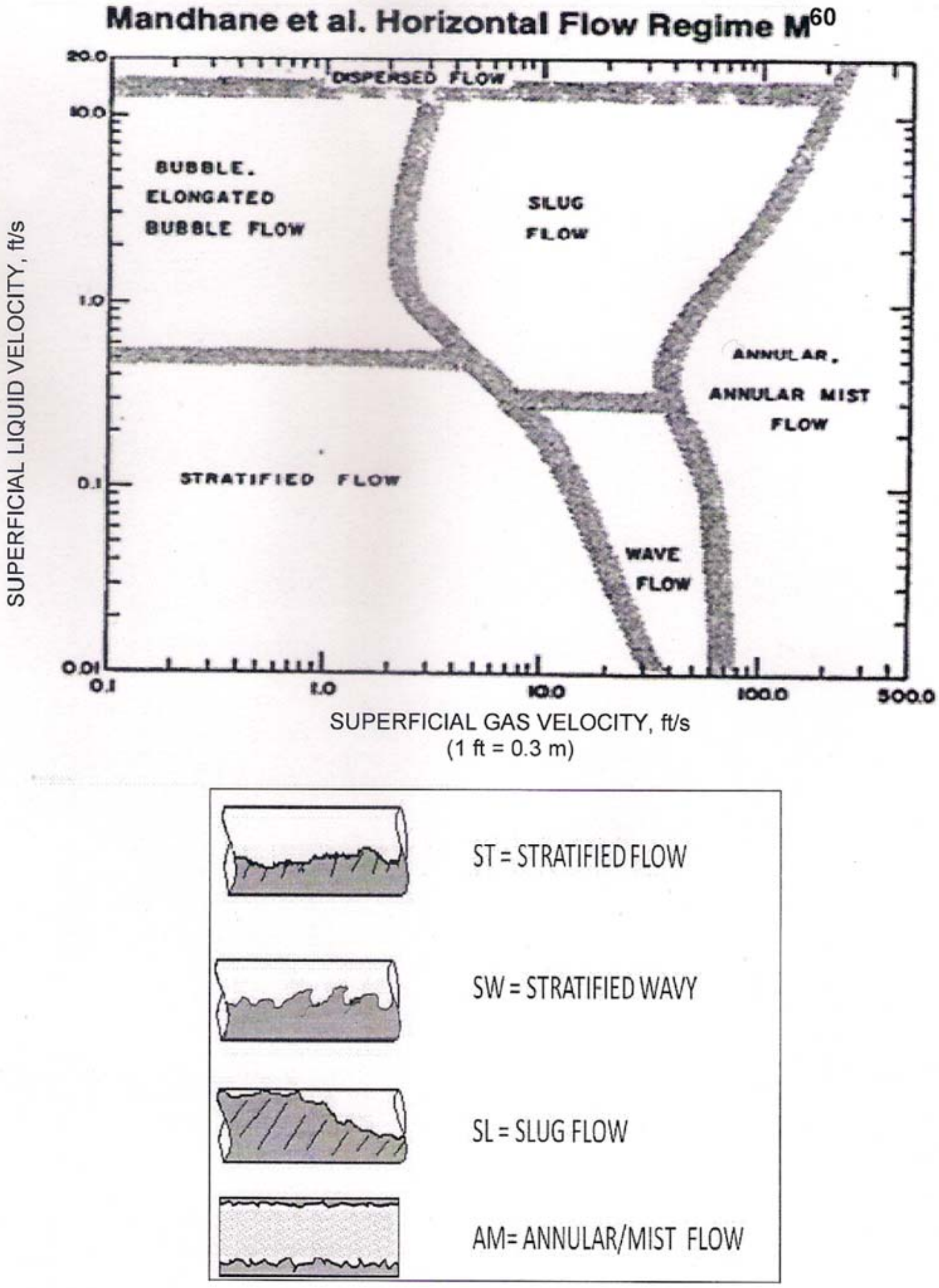

Figure C2: Example of a flow pattern map.
Figure reprinted with permission from the Gas Processors Association.[17]

Figure C3 shows an example of WG-ICDA subregion identification using Pipeline Segment A-B from Figure C1. In this example, which involves only WG-ICDA Regions #4 and #5, only one WG-ICDA subregion was present in WG-ICDA Region #4, but four different WG-ICDA subregions were present in WG-ICDA Region #5. (NOTE: Example 2 in this appendix provides further details of this procedure.)

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[17] Gas Processors Association (GPA), 6526 E. 60th St., Tulsa, OK 74145.

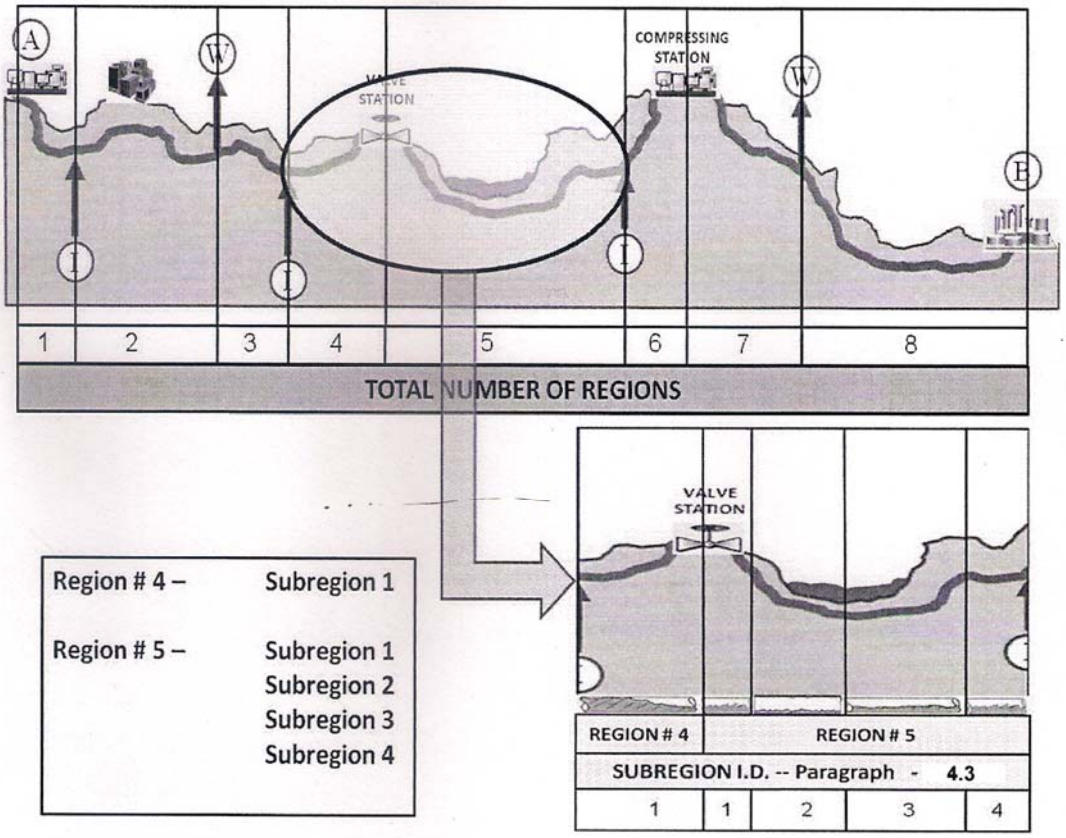

Figure C3: WG-ICDA Subregion identification example.

EXAMPLE 2—WG-ICDA REGION AND SUBREGION IDENTIFICATION, AND ASSESSMENT SITE SELECTION[84]

Figure C4 shows an example of a pipeline segment that has been assessed. In accordance with Paragraph 3.4, a pipeline segment from point A to point B that is 10,428 m (34,214 ft) in total length was defined.

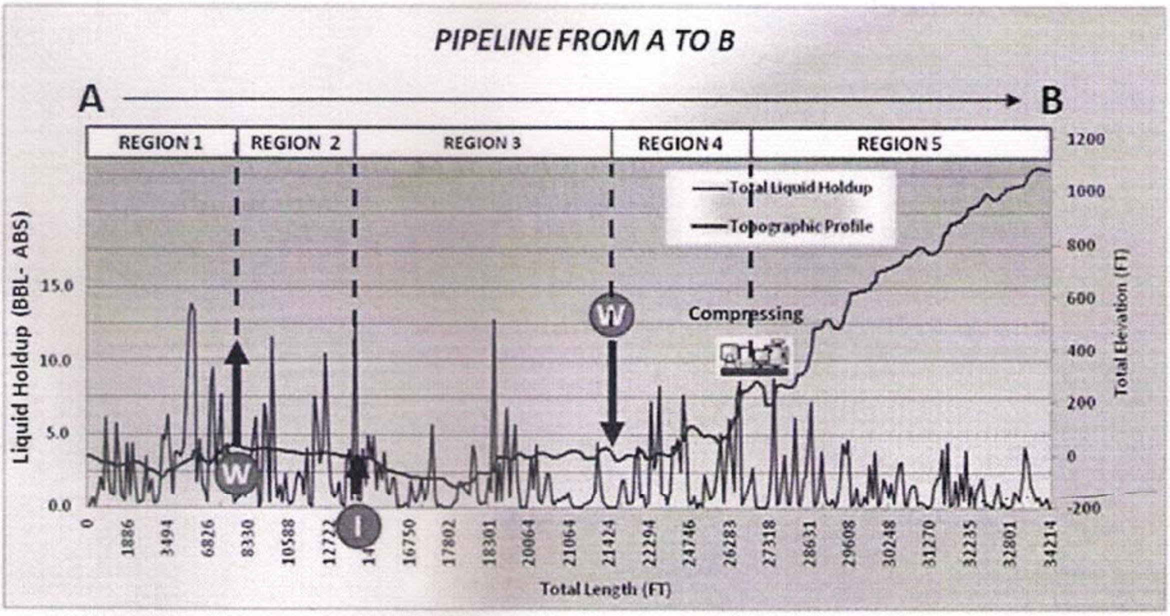

Figure C4: Graphical representation of the example pipeline segment showing elevation profile, liquid holdup, and WG-ICDA regions identified. (1 ft = 0.3 m)

WG-ICDA Region Identification

Based on inputs, withdrawals, and unit operation changes, five WG-ICDA regions were identified for this pipeline segment (see Paragraph 3.5). (NOTE: Example 1 in this appendix provides further details of this procedure.)

WG-ICDA Subregion Identification

The data categorized as Importance Level 1 that had been collected (see Paragraph 3.2) were used as input to perform the multiphase flow modeling (see Paragraph 4.2). An ICPM with an integrated multiphase flow model may also be selected so that the corrosion rate modeling may be performed at the same time as multiphase flow modeling.

Multiphase flow and corrosion rate modeling provided the following information at discrete points along the pipeline segment:

- Pressure;
- Temperature;
- Superficial gas velocity;
- Superficial liquid velocity;
- Mixture velocity;
- Liquid holdup;
- Flow pattern; and

- Corrosion rate.

Flow modeling and corrosion rate results were calculated at pipeline increments of less than or equal to 50 m (82 ft).

The wall loss percentage was then calculated from the corrosion rate at each discrete point along the pipeline segment in accordance with Paragraph 4.4.3.

The liquid holdup results were plotted along with the pipeline segment elevation profile, as shown in Figure C4. The use of figures helps to visually locate the WG-ICDA regions and subregions as well as helps with identifying the assessment sites.

The multiphase flow modeling identified all flow patterns that developed in each WG-ICDA region. In this particular case, 10 WG-ICDA subregions were identified within WG-ICDA Region 1. Figure C5 shows the resulting WG-ICDA subregions that were identified in WG-ICDA Region 1 based on the following indicated changes in flow pattern predicted by the multiphase flow model:

- Subregion 1 → ST
- Subregion 2 → SL
- Subregion 3 → SW
- Subregion 4 → SL
- Subregion 5 → AM
- Subregion 6 → SL
- Subregion 7 → SW
- Subregion 8 → AM
- Subregion 9 → SW
- Subregion 10 → SL

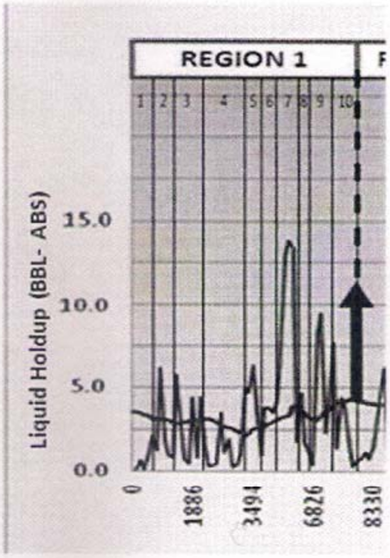

Figure C5: Graphical representation of WG-ICDA subregions identified within WG-ICDA Region 1.

Assessment Site Selection

To assist in the assessment site selection, a summary table (see Paragraph 4.5.4) was assembled to document the data and information developed to this point in the process. Table C1 is an example summary table for WG-ICDA Region 1 only, which includes all the results from the multiphase flow simulations, corrosion rates, and calculated wall losses. A complete summary table would include all WG-ICDA regions and corresponding subregions. NOTE: The values shown in Table C1 are only referential; they may not coincide exactly with real values.

Preselection (see Paragraph 4.5.3)

For assessment site preselection, two criteria were used.

Criterion 1: Wall Loss (see Paragraph 4.5.3.1)

In accordance with Paragraph 4.5.3.1.1, the corresponding wall loss percentage averages were calculated for each subregion within WG-ICDA Region 1, and the results added to Table C1. For this example, the average wall loss percentage values were: Subregion 1 = 11.29%; Subregion 2 = 17.86%; Subregion 3 = 17.23%; etc. NOTE: Table C1 shows the results for all the subregions contained in WG-ICDA Region 1 only; however, this process was completed for all WG-ICDA regions and subregions within Pipeline Segment A-B.

In accordance with Paragraph 4.5.3.1.2, all wall loss percentage values for locations within each WG-ICDA subregion that were equal to or greater than the average value were selected. In Table C1, the assessment sites within each subregion that were preselected using this criterion were marked using dark gray shading.

Criterion 2: Liquid Holdup (see Paragraph 4.5.3.2)

In accordance with Paragraph 4.5.3.2.1, the corresponding liquid holdup averages were calculated for each subregion within WG-ICDA Region 1, and the results added to Table C1. For this example, the average liquid holdup values were: Subregion 1 = 1.14 absolute barrels; Subregion 2 = 3.05 absolute barrels; Subregion 3 = 2.61 absolute barrels; etc. NOTE: Table C1 shows the results for all the subregions contained in WG-ICDA Region 1 only; however, this process was completed for all WG-ICDA regions and subregions within Pipeline Segment A-B.

In accordance with Paragraph 4.5.3.2.2, all liquid holdup values for locations within each WG-ICDA subregion that were equal to or greater than the average value were selected. In Table C1, the assessment sites within each subregion that were preselected using this criterion were marked using dark gray shading.

Combine Both Preselection Criteria (see Paragraph 4.5.3.3)

In accordance with Paragraph 4.5.3.3, both criteria were combined to preselect assessment sites within each subregion. For WG-ICDA Region 1, the preselected assessment sites were indicated in Table C1 by the cells in the "Preselected Assessment Site" column that read "Yes."

Final Selection (see Paragraph 4.6)

The minimum number of final assessment sites was determined using the Table 3 criteria as a function of the pipeline segment length. In this example, the length of Pipeline Segment A-B is approximately 10 km (6.5 mi). According to Table 3, the minimum number of final assessment sites is six. More assessment sites may be selected or they may be prioritized by the SME based on any other criteria that has been technically justified and agreed to by the pipeline operator.

Six final sites were selected by the SME. Two of these were in WG-ICDA Region 1; one in Subregion 1 and one is Subregion 4.

In accordance with Paragraph 4.6.4, a final assessment site selection table was constructed (see Table C2).

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup[(A)]	Superficial Liquid Velocity[(A)]	Superficial Gas Velocity[(A)]	Mixture Velocity[(A)]	Flow Pattern[(A)]	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	1	38	–4	649.76	99.46	0.40	0.022	1.422	1.443	ST	0.63	1.40	No
						119	–13	649.16	99.03	0.60	0.035	2.132	2.167	ST	2.38	4.77	No
						178	–14	649.10	98.98	0.20	0.012	0.710	0.723	ST	4.88	9.76	No
						255	–23	648.78	98.47	***1.25***	0.082	4.440	4.521	ST	7.24	***14.47***	Yes
						337	–24	647.98	98.26	***1.35***	0.088	4.795	4.883	ST	8.93	***17.86***	Yes
						419	–24	647.74	97.98	***1.78***	0.116	6.322	6.439	ST	6.01	***12.02***	Yes
						508	–24	647.48	97.90	***2.38***	0.174	8.450	8.625	ST	9.39	***18.78***	Yes
									Average	1.14					Average	11.29	
					2	586	–25	646.97	97.60	1.24	1.82	10.64	12.454	SL	8.31	16.62	No
						668	–25	645.93	97.48	2.24	3.28	15.24	18.521	SL	7.68	15.36	No
						748	–25	645.01	97.14	***3.23***	2.37	21.96	24.342	SL	9.26	***18.51***	Yes
						829	–26	644.95	96.97	***4.23***	3.10	20.76	31.879	SL	9.56	***19.12***	Yes
						911	–26	644.85	96.79	***5.38***	3.94	36.61	40.545	SL	11.55	***23.10***	Yes
						993	–26	644.74	96.46	***6.25***	4.58	42.53	47.102	SL	14.12	***28.24***	Yes
						1,065	–28	644.63	96.33	2.23	2.07	15.15	17.214	SL	5.38	10.77	No
						1,048	–30	644.01	96.00	1.47	1.58	10.01	11.592	SL	6.27	12.55	No
						1,230	–36	643.53	95.78	1.14	1.29	7.77	9.057	SL	8.23	16.46	No
									Average	3.05					Average	17.86	

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions
(continued)

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup$^{(A)}$	Superficial Liquid Velocity$^{(A)}$	Superficial Gas Velocity$^{(A)}$	Mixture Velocity$^{(A)}$	Flow Pattern$^{(A)}$	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	3	1,312	–43	643.09	95.85	2.54	0.166	11.273	11.439	SW	12.09	***24.176***	No
						1,394	–43	642.24	95.25	***2.77***	0.662	13.099	13.761	SW	6.42	12.837	No
						1,476	–43	641.81	95.09	***6.77***	0.809	24.034	24.844	SW	11.20	***22.402***	Yes
						1,558	–41	641.59	95.00	***5.50***	0.146	19.544	19.690	SW	11.46	***22.929***	Yes
						1,640	–39	641.49	94.96	***2.75***	0.146	15.472	15.619	SW	10.56	***21.124***	Yes
						1,722	–37	641.38	94.92	***2.70***	0.113	15.166	15.281	SW	5.28	10.565	No
						1,804	–36	640.99	94.78	1.09	0.052	15.816	15.868	SW	6.79	13.580	No
						1,829	–35	640.61	94.64	***4.28***	0.193	18.998	19.191	SW	8.33	16.665	No
						1,863	–34	640.40	94.58	0.92	0.043	8.217	8.260	SW	7.34	14.674	No
						1,886	–34	640.27	94.53	1.74	0.082	15.475	15.556	SW	11.81	***23.612***	No
						2,093	–30	639.07	94.13	1.54	0.075	13.741	13.816	SW	5.57	11.149	No
						1,960	–30	638.86	94.07	***4.37***	0.219	19.437	19.656	SW	2.64	5.282	No
						2,331	–26	637.69	93.72	***2.82***	0.146	10.050	10.196	SW	8.09	16.187	No
						2,395	–25	637.31	93.61	0.55	0.029	1.945	1.974	SW	7.11	14.229	No
						2,042	–30	637.04	93.54	0.70	0.038	14.560	14.598	SW	12.88	***25.759***	No
						2,124	–37	636.64	93.45	0.65	0.036	13.486	13.522	SW	10.26	***20.523***	No
									Average	2.61					Average	17.23	

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions
(continued)

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup(A)	Superficial Liquid Velocity(A)	Superficial Gas Velocity(A)	Mixture Velocity(A)	Flow Pattern(A)	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	4	2,206	–47	636.13	93.34	2.80	0.468	24.113	24.582	SL	19.99	***39.986***	No
						2,288	–49	635.26	93.08	2.13	1.100	18.395	19.495	SL	2.88	5.758	No
						2,370	–52	634.91	92.99	3.93	2.082	33.969	36.051	SL	14.15	28.291	No
						2,452	–56	634.26	92.83	0.52	0.281	4.508	4.790	SL	18.73	37.466	No
						2,534	–64	633.75	92.74	2.81	1.541	24.327	25.868	SL	9.68	19.352	No
						2,616	–84	632.72	92.54	3.90	2.187	33.744	35.931	SL	4.35	8.700	No
						2,698	–84	632.72	92.54	2.00	0.373	17.277	17.651	SL	13.53	27.059	No
						2,780	–72	631.66	92.34	***9.33***	1.783	80.837	82.620	SL	39.13	***78.254***	Yes
						2,862	–59	630.69	92.17	2.54	0.497	22.026	22.522	SL	11.21	22.427	No
						2,944	–57	629.08	91.86	***8.11***	1.635	70.471	72.106	SL	36.81	***73.613***	Yes
						3,026	–52	628.16	91.70	1.83	1.142	15.946	17.087	SL	35.85	***71.710***	No
						3,108	–51	627.96	91.66	***7.63***	1.604	66.464	68.068	SL	34.30	***68.606***	Yes
						3,190	–43	627.17	91.54	***7.67***	1.627	66.647	68.474	SL	9.28	18.569	No
						3,272	–35	626.38	91.42	***7.10***	1.527	61.885	63.412	SL	22.42	***44.849***	Yes
						3,354	–47	625.65	91.31	1.69	0.369	14.793	15.162	SL	26.40	***52.799***	No
									Average	4.27					Average	39.83	

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions
(continued)

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup(A)	Superficial Liquid Velocity(A)	Superficial Gas Velocity(A)	Mixture Velocity(A)	Flow Pattern(A)	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	5	3,436	–21	624.75	91.18	4.39	0.971	39.730	40.702	AM	29.51	**59.026**	No
						3,518	–17	623.04	90.94	5.16	1.163	46.712	47.875	AM	29.32	**58.634**	No
						3,600	–11	619.96	90.57	5.54	1.289	50.384	51.673	AM	11.78	23.565	No
						3,682	18	617.23	90.27	**26.69**	6.411	97.432	103.843	AM	31.65	**63.300**	Yes
						6,764	25	614.12	90.00	3.28	0.807	12.018	12.825	AM	7.83	15.668	No
						3,846	16	613.48	89.90	5.63	1.409	50.090	51.498	AM	32.95	**65.905**	No
						3,928	–8	611.74	89.80	3.51	0.883	12.922	13.804	AM	26.77	**53.536**	No
						4,010	–19	611.02	89.78	6.34	1.599	58.582	60.181	AM	34.27	**68.544**	No
						4,092	–26	610.60	89.77	2.02	0.509	49.849	50.358	AM	23.89	47.784	No
						4,174	–28	610.46	89.78	**16.53**	4.154	61.167	65.322	AM	32.02	**64.031**	Yes
						4,256	–13	608.81	89.64	1.13	0.286	45.537	45.823	AM	11.23	22.467	No
									Average	7.29					Average	49.31	
					6	4,338	4	606.92	89.54	**3.65**	1.111	13.564	14.675	SL	6.79	13.577	No
						4,420	8	606.45	89.44	**3.70**	1.134	13.777	14.911	SL	7.16	14.323	No
						4,502	16	606.65	89.34	**3.68**	1.140	10.286	11.425	SL	13.14	**26.280**	Yes
						4,584	30	604.13	89.24	2.70	0.840	10.064	10.905	SL	8.22	16.443	No
						4,666	33	603.86	89.23	**3.46**	1.081	12.939	14.020	SL	13.71	**27.418**	Yes
						4,748	37	602.88	89.13	**3.67**	1.151	13.738	14.889	SL	2.71	5.418	No
						4,830	39	601.98	89.03	3.05	0.965	11.436	12.401	SL	10.91	**21.827**	No
						4,912	39	601.63	89.03	0.61	0.192	2.272	2.464	SL	19.73	**39.467**	No
						4,994	37	601.48	89.04	**3.76**	1.190	35.295	36.485	SL	8.48	16.969	No
									Average	3.14					Average	20.19	

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions
(continued)

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup(A)	Superficial Liquid Velocity(A)	Superficial Gas Velocity(A)	Mixture Velocity(A)	Flow Pattern(A)	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	7	5.076	34	601.24	89.06	3.68	0.968	36.862	37.830	SW	7.26	***14.522***	No
						5,158	32	601.01	89.07	3.98	0.522	39.888	40.409	SW	4.96	9.928	No
						5,240	28	600.63	89.07	4.87	0.636	48.838	49.474	SW	4.72	9.448	No
						5,322	26	600.40	89.08	***8.67***	0.753	32.625	33.378	SW	6.89	***13.779***	Yes
						5,404	25	600.04	89.09	***8.38***	0.435	31.554	31.989	SW	7.90	***15.802***	Yes
						5,486	23	599.37	89.08	***12.19***	0.394	45.953	46.347	SW	8.09	***16.173***	Yes
						5,568	25	598.14	88.98	***13.75***	0.356	51.912	52.268	SW	5.18	10.350	No
						5,650	26	596.62	88.88	***12.87***	3.352	48.704	52.056	SW	4.14	8.281	No
						5,732	26	596.61	88.89	3.01	0.786	30.451	31.237	SW	3.30	6.600	No
						5,814	26	596.51	88.90	2.81	0.081	28.407	28.488	SW	3.79	7.581	No
						5,896	26	594.72	88.88	2.21	0.064	22.377	22.440	SW	10.45	***20.896***	No
						5,978	24	593.15	88.86	2.02	0.520	20.556	21.086	SW	11.30	***22.609***	No
									Average	6.54					Average	13.00	
					8	6,060	24	593.06	88.87	***2.34***	0.598	66.961	67.559	AM	28.68	***57.358***	Yes
						6,142	23	590.03	88.77	***2.68***	0.682	76.916	77.598	AM	27.05	***54.106***	Yes
						6,224	23	589.33	88.77	***4.20***	3.188	80.644	83.832	AM	25.37	***50.737***	Yes
						4,306	23	589.16	88.78	***3.22***	2.439	82.605	85.044	AM	25.28	***50.556***	Yes
						6,388	21	588.70	88.79	1.25	0.942	80.126	81.069	AM	24.14	***48.272***	No
						6,470	20	588.58	88.80	1.23	0.927	79.149	80.077	AM	24.52	***49.041***	No
						6,552	17	587.83	88.80	1.20	0.299	76.973	77.272	AM	23.80	***47.593***	No
						6,634	16	587.69	88.81	1.20	0.297	76.786	77.082	AM	1.38	2.761	No
						6,716	15	587.61	88.82	1.18	0.293	75.841	76.134	AM	1.22	2.444	No
									Average	2.06					Average	40.32	

Table C1
Summary Table for WG-ICDA Region 1 and Its Subregions
(continued)

Region #	Paragraph # for Criteria	Length of Region	Coordinates	Description	Subregion #	Total Length	Total Elevation	Pressure	Temperature	Total Liquid Holdup(A)	Superficial Liquid Velocity(A)	Superficial Gas Velocity(A)	Mixture Velocity(A)	Flow Pattern(A)	Corrosion Rate	Wall Loss	Preselected Assessment Sites (according to Paragraph 4.5.3.3)
		ft				ft	ft	psig	°F	bbl abs.	ft/s	ft/s	ft/s		mpy	%	
Region 1	3.5.1	7,864.50	From UTM E 0474691.692 A N 2037493.562 to UTM E 0474729.044 A N 2037210.186	Region 1 goes from the beginning of the pipeline, from exit pig trap located in installation (NAME) to first withdrawal located near (ROAD)	9	6,798	13	587.42	88.84	1.08	0.134	4.166	4.300	SW	2.53	5.052	No
						6,880	10	586.78	88.84	0.90	0.111	3.475	3.586	SW	18.34	**36.680**	No
						6,962	9	586.09	88.84	0.86	0.105	3.325	3.430	SW	4.22	8.432	No
						7,044	8	585.53	88.84	**8.40**	1.025	32.515	33.539	SW	5.59	11.181	No
						7,126	8	585.30	88.85	**9.67**	0.392	6.243	6.635	SW	17.25	**34.503**	Yes
						7,208	9	584.20	88.83	2.47	0.598	9.581	10.179	SW	16.13	**32.261**	No
						7,290	9	584.14	88.84	**7.35**	1.774	28.543	30.317	SW	24.15	**48.302**	Yes
									Average	4.39					Average	25.20	
					10	7,372	9	584.11	88.85	**7.50**	1.807	29.129	30.937	SL	10.46	**20.922**	Yes
						7,454	9	582.04	88.82	**7.65**	1.833	44.660	46.493	SL	11.62	**23.233**	Yes
						7,536	10	580.50	88.80	1.25	2.967	11.799	14.765	SL	11.07	**22.149**	No
						7,618	10	579.64	88.79	2.50	2.947	15.497	18.444	SL	7.77	**15.537**	No
						7,700	10	578.46	88.78	**3.76**	4.406	14.750	19.157	SL	7.15	14.298	No
						7,782	9	575.47	88.75	2.35	2.721	9.257	11.979	SL	1.70	3.402	No
						7,864	9	574.14	88.74	1.24	1.418	4.906	6.324	SL	1.67	3.340	No
									Average	3.75					Average	14.70	

(A) These values were obtained using calculations described in a commercially available hydraulic model using inputs such as pipeline topography, inside diameter and length, inlet pressure and temperature, and gas composition. The liquid holdup values presented are only for illustration purposes.

Table C2
Final Assessment Site Selection

Region #	Subregion #	Coordinates	Total Length	Total Evaluation	Total Liquid Holdup	Flow Pattern	Corrosion Rate	Wall Loss	Preselected Assessment Sites	Comments
			ft	ft	bbl abs.		mpy	%		
1	1		508.05	–24.28	2.38	ST	9.391	18.782	Yes	Located in a high-consequence area
	4		2,944.50	–56.73	8.11	SL	36.806	73.613	Yes	Based on wall loss and liquid holdup
2	3		9,358.63	25.26	12.28	SL	16.056	32.111	Yes	Based on wall loss and liquid holdup
3	3		14,719.80	–8.37	9.88	AM	20.012	40.023	Yes	Based on wall loss and has a history of previous failures
4	8		25,910.12	57.65	10.27	ST	26.592	53.183	Yes	Based on rupture history
5	15		32,440.55	967.39	10.85	SW	9.042	22.606	Yes	Near a river